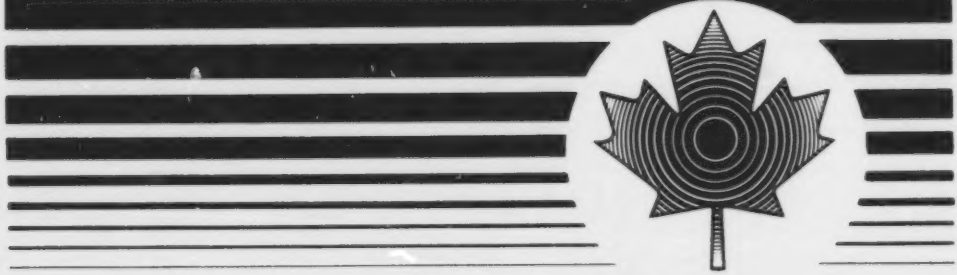
Replacement Costs for Oil and Gas in Western Canada: Methodologies and Application

Michele McLachlan



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METHODOLOGIES AND APPLICATION

MICHELE McLACHLAN

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Author: Michele McLachlan

CANADIAN ENERGY RESEARCH INSTITUTE
3512 - 33RD STREET N.W.
CALGARY, ALBERTA
CANADA T2L 2A6

TELEPHONE: (403) 282-1231
FAX. NO.: (403) 284-4181

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Preface

The author wishes to express her gratitude to the advisory committee of industry, industry association, and government representatives. The direction and insights which they provided during the course of the study and their comments on drafts of the report were most helpful.

Special thanks are due to a number of the Institute's staff: Beverly Kovacs processed the interim drafts and final manuscript; Megan Murphy developed the graphics; Nancy Sanford provided proofreading assistance; Janice Morrison oversaw the publication of the report; Zaytoon Janjua and Wendy Faid of the I.N. McKinnon Memorial Library gathered source materials; Dr. Gerry Angevine, Anthony Reinsch, Michelle Heath, Leonard Coad and David Maerz provided their support and guidance throughout the project.

EXECUTIVE SUMMARY

This report examines two perspectives of replacement costs and the associated methodologies. It investigates their application to Alberta and Saskatchewan.

Definitions

"Short-term replacement costs" refer to the per unit costs incurred to obtain hydrocarbon reserves additions through exploration or development in a particular year. Short-term replacement costs are calculated by matching the exploration and development expenditures made in a particular year with the reserves additions booked in that year.

"Long-term replacement costs" refer to the per unit costs incurred during the exploration and development stages of the upstream cycle for specific reserves. Long-term replacement costs are calculated by matching the exploration and development components of the expenditure profile pertaining to reserves discovered in a particular year with the estimated fully appreciated reserves from that discovery year.

Limitations of the Analysis

Short-term and long-term replacement costs are analysed on an aggregate level in this study. Numerous methodological and data limitations are encountered with these aggregate analyses. The methodological problems are primarily related to the difficulty of determining methodologies that reflect the "average" situation; the data problems are primarily related to difficulties in extracting the required data from that which is available.

Short-Term Replacement Cost Estimates

Short-term replacement cost estimates represent the weighted average of the finding cost and development cost components for the reserves additions from a particular year. Short-term replacement cost estimates are presented for Alberta and Saskatchewan.

Short-term replacement cost estimates for crude oil equivalent in 1988 are $8.94 and $4.70 per barrel of oil equivalent (BOE) for Alberta and Saskatchewan, respectively.

Short-term replacement costs have also been estimated separately for crude oil and marketable natural gas. Estimates for Alberta and Saskatchewan, respectively, are $9.16 and $4.42 per barrel for crude oil, and $0.72 and $0.47 per thousand cubic feet (Mcf) (or $8.54 and $5.59 per BOE) of marketable natural gas.

Caution is advised when comparing results from different jurisdictions, as numerous factors can contribute to the results being incomparable and, perhaps, misleading. This is discussed further in Chapter 4.

Long-Term Replacement Cost Estimates

Long-term replacement cost estimates represent the sum of the finding cost and development cost components for the fully appreciated reserves from a particular discovery year. An analysis of finding costs and long-term replacement costs has been conducted for Alberta only, due to the lack of adequate reserves data for Saskatchewan. (These costs are shown in Figure 1.)

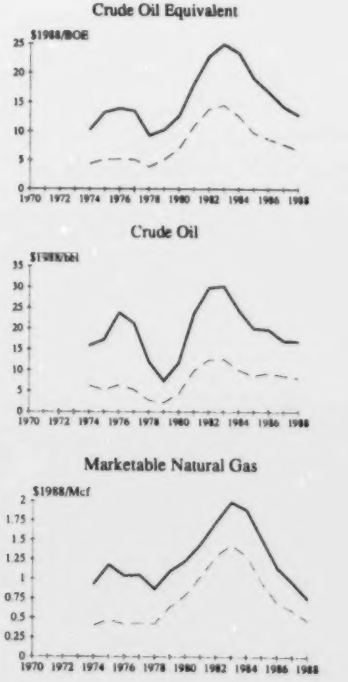
Finding costs, as well as long-term replacement costs, for crude oil equivalent in Alberta continue the downward trend which began in the early 1980s. The 1988 three-year moving average estimates show finding costs of $6.85 per BOE and long-term replacement costs of $12.69 per BOE.

Downward trends are also evident in costs calculated separately for crude oil and marketable natural gas in Alberta. The 1988 three-year moving average estimates for crude oil show finding costs of $8.17 per barrel and long-term replacement costs of $17.28 per barrel; the 1988 three-year moving average estimates for marketable natural gas show finding costs of $0.47 per Mcf (or $5.55 per BOE) and long-term replacement costs of $0.70 per Mcf (or $8.24 per BOE).

Suggestions for Improving the Replacement Cost Estimates

More accurate replacement cost estimates can be obtained either by conducting the analyses using disaggregate data or by resolving the present problems with the aggregate reserves data. It will only become possible to obtain more accurate replacement cost

Figure 1
Alberta Long-Term Replacement Costs



NOTE: Base case three-year moving averages.

estimates from aggregate analyses if changes are made to the method by which aggregate reserves data are published.

- First, it will be necessary to isolate the portion of reserves additions that has occurred due to expenditures, rather than due to factors such as changes in economic conditions. This would require that the published aggregate reserves data be disaggregated to a greater extent than at present, using standardized definitions of terms such as "extensions" and "revisions."

- Second, if accurate annual cost estimates are to be calculated, the reserves estimates must be made to reflect the reserves additions from each calendar year.

The improvements to the aggregate reserves data can only be made by the organizations that generate the reserves data: this requires the cooperation of the organizations that publish the aggregate data and the organizations that provide the disaggregate data that are compiled. Until these necessary improvements are made, the comparison of individual corporate performance to average industry performance is a potentially misleading exercise.

Chapter 1

INTRODUCTION

1.1 Background to the Report

The initial objectives of this study were twofold: to present a methodology for estimating replacement costs for oil and gas, and to provide estimates of replacement costs for Alberta and Saskatchewan. As the study progressed, however, it became necessary to change the focus due to the ambiguous current usage of the term "replacement costs" and the numerous methodological and data limitations encountered in attempting to estimate them.

The term "replacement cost" is presently being used to refer to two distinct concepts. This study examines the two different perspectives of the relationship between expenditures on exploration and development activity in the petroleum industry and the reserves additions that they generate.

The first perspective matches exploration and development expenditures in a particular year with the reserves additions booked in that year that resulted from those expenditures, thus determining the per unit cost of obtaining reserves additions. This measure, termed the "short-term replacement cost" for crude oil and natural gas, is relevant for short-term issues such as cash flow decisions.

The second perspective matches the exploration and development expenditure profile related to the reserves discovered in a particular year with the fully appreciated reserves from that discovery year, thus providing an estimate of the per unit costs incurred during the exploration and development stages of the energy cycle. This measure, termed the "long-term replacement cost" for crude oil and natural gas, is relevant for long-term investment decisions.

The main contribution of this study is to clarify the measurement of replacement costs. Because of the different approaches which can be used to match expenditures and reserves additions, any replacement cost estimate must be interpreted carefully. This study provides a separate analysis for each of the above perspectives, an explanation of the differences between them, and a discussion of the limitations of the analyses.

1.2 Report Outline

Chapter 2 introduces the concept of replacement costs and discusses the two alternative perspectives.

Chapter 3 identifies and briefly discusses some of the limitations of the analyses, discusses their implications, and suggests how some of the limitations could be overcome.

Chapters 4 and 5 are essentially two separate studies, providing analyses of replacement costs for each of the perspectives mentioned above. Each chapter includes a thorough discussion of the methodology employed in the analysis, followed by a discussion of the results obtained.

The background data used in the analyses are presented in Appendix A. The results are presented in tabular form in Appendices B and C.

Chapter 2

REPLACEMENT COSTS: TWO ALTERNATIVE VIEWS

2.1 General Overview

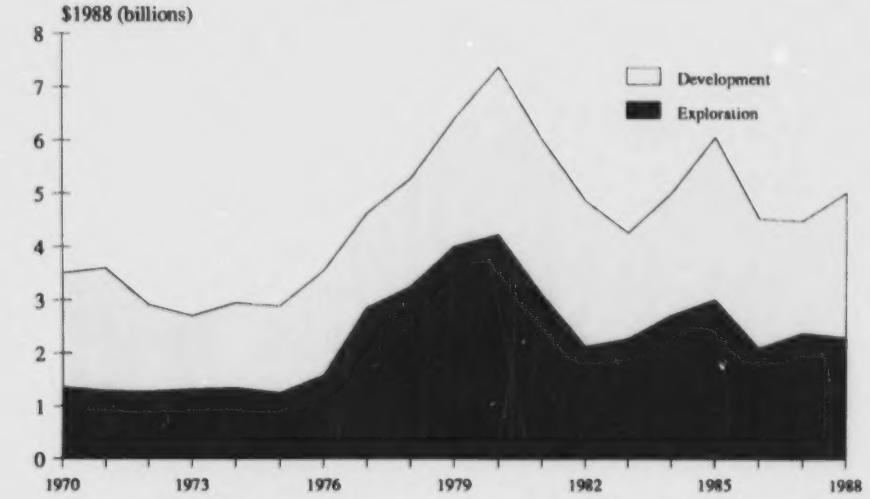
In order to continue producing oil and gas in the future, firms in the petroleum industry must maintain their stock of below ground reserves. Reserves that are produced can be replaced by exploring for new discoveries or by extensions to existing reserves. Since the exploration and development costs incurred to replace produced reserves affect the profitability of oil and gas activity, an analysis of these costs is of interest to industry participants.

The per unit cost of obtaining reserves additions is determined by matching the upstream expenditures made with the volume of reserves additions generated as a result of the expenditures. Thus, changes in the per unit cost can occur as a result of changes in either the level of expenditures or the volume of reserves additions. The variations in exploration and development expenditures, in reserves additions for crude oil, and in reserves additions for marketable natural gas in Alberta in recent years are illustrated in Figures 2.1, 2.2 and 2.3, respectively. The figures illustrating reserves additions also show production levels for the same time period, thus indicating the extent to which the produced reserves were being replaced annually. The corresponding information for Saskatchewan is presented in Figures 2.4 to 2.6.

2.2 Short-Term Replacement Costs vs. Long-Term Replacement Costs

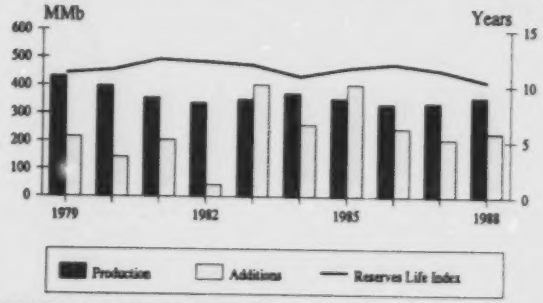
At first glance, it may seem that an analysis of replacement costs would be quite straightforward. However, the analysis is complicated by the fact that replacement costs can be viewed from more than one perspective. Replacement cost information can be of relevance for both short-term and long-term decisions. Regardless of whether a short-term or a long-term question is being addressed, the same general formula is used to calculate replacement costs: expenditures are divided by the reserves additions resulting from those expenditures.

Figure 2.1
Alberta
Exploration and Development Expenditures



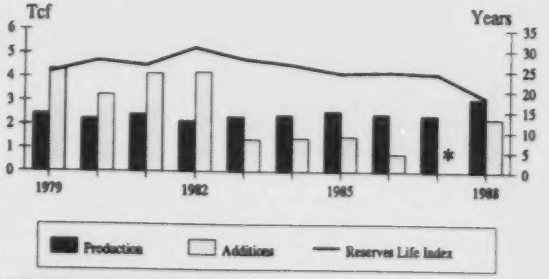
SOURCES: Tables A.7 and A.8.

Figure 2.2
Alberta Crude Oil
Historical Reserves Replacement



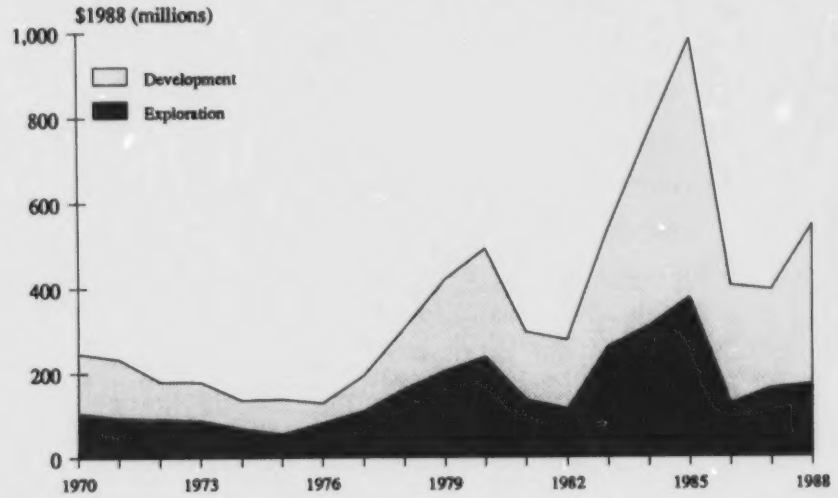
SOURCES: Alberta Energy Resources Conservation Board, CERI.

Figure 2.3
Alberta Marketable Natural Gas
Historical Reserves Replacement



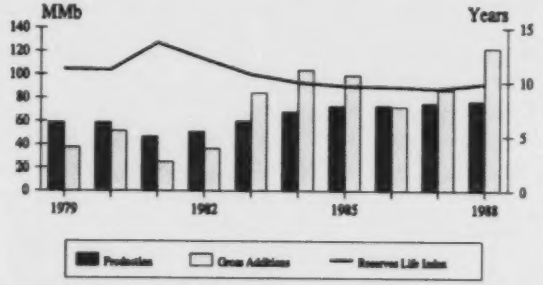
SOURCES: Alberta Energy Resources Conservation Board, CERI.
*Gross Additions = 0.

Figure 2.4
Saskatchewan
Exploration and Development Expenditures



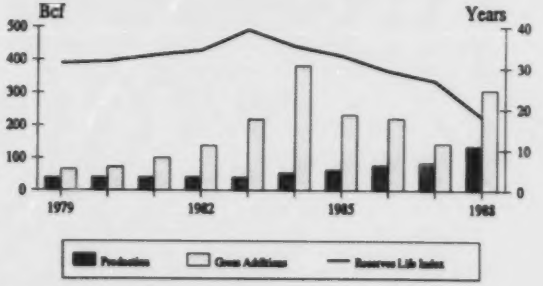
SOURCES: Tables A.9 and A.10.

Figure 2.5
Saskatchewan Crude Oil
Historical Reserves Replacement



SOURCES: Saskatchewan Energy and Mines, CERI.

Figure 2.6
Saskatchewan Marketable Natural Gas
Historical Reserves Replacement



SOURCES: Saskatchewan Energy and Mines, CERI.

However, expenditures and reserves additions are matched differently for analyses from the different perspectives.

2.2.1 Short-Term Replacement Costs

In this study, "short-term replacement costs" provide information pertinent to issues such as short-term cash flow decisions. An analysis of short-term replacement costs involves modelling the exploration and development expenditure process related to reserves additions generated in a particular year. The reserves additions are assumed to result from the exploration expenditure profile (including previous expenditures on land acquisitions and on geological and geophysical work, and current exploratory drilling expenditures) and current development expenditures.[1] The short-term replacement costs are calculated by dividing the sum of exploration and development expenditures in any year by the total reserves additions booked in that year, thus providing an estimate of the per unit costs incurred in that year to obtain reserves additions. As reserves additions represent future cash flow to a company, an estimate of the cost at a particular point in time of obtaining reserves additions should be useful for short-term cash flow considerations.

2.2.2 Long-Term Replacement Costs

"Long-term replacement costs" provide information which is relevant for strategic planning and long-term investment decisions. An analysis of long-term replacement costs involves modelling the exploration and development expenditure profile related to reserves discovered in a particular year: land acquisition, geological and geophysical work, exploratory drilling and reserves delineation. In this study, aggregate reserves estimates are used, and it is assumed that reserves tend to increase (i.e., appreciate) as more information about the reserves is obtained. The long-term replacement costs are calculated by dividing the sum of the expenditures pertaining to the exploration and development profile of the reserves discovered in a particular year by the estimate of fully appreciated reserves from that discovery year. This provides an estimate of the per unit costs incurred during the exploration and development stages of the energy cycle for reserves discovered in a particular year.

The analysis of long-term replacement costs in this study is an extension of the analysis conducted in the series of finding cost studies previously published by the Canadian Energy Research Institute (CERI).[2] These studies matched the costs incurred at the

exploration stage of the energy cycle with the fully appreciated reserves from a particular discovery year. In this study, the analysis also includes development expenditures in order to ascribe costs to the process of reserves appreciation.

2.2.3 Reconciliation of Short-Term and Long-Term Perspectives

The estimates of short-term replacement costs and long-term replacement costs are very different and have very different meanings. For both analyses, it is theoretically possible to break down the replacement cost estimates into the separate finding cost and development cost components. The major difference in the interpretation of the replacement cost calculations from the two perspectives is that the short-term replacement cost estimates represent the weighted average of the finding cost and development cost components for the **reserves additions from a particular year**, whereas the long-term replacement cost estimates represent the sum of the finding cost and development cost components for the **fully appreciated reserves from a particular discovery year**. Because of the differences, it is critical that any replacement cost estimates be viewed in light of the methodology used in their calculation.

In addition to the methodological considerations, data limitations must also be considered when analysing replacement cost estimates. The following chapter discusses some limitations of the results caused by methodological and data limitations.

Footnotes

[1]A development expenditure profile may be more appropriate, but due to difficulties involved with matching expenditures and reserves, the current expenditures are used.

[2]Michele McLachlan, *Oil and Gas Finding Costs in Alberta: 1970-1987*, CERI Research Report 89-1 (Calgary, Alberta: Canadian Energy Research Institute, May 1989); Janice L. Pasay, *Oil and Gas Finding Costs in Alberta: 1970-1986*, CERI Research Report 88-1 (Calgary, Alberta: Canadian Energy Research Institute, May 1988); Janice L. Pasay, *Oil and Gas Finding Costs in Alberta: 1970-1985*, CERI Research Report 87-1 (Calgary, Alberta: Canadian Energy Research Institute, January 1987); and Z. Charles Slagorsky and Janice L. Pasay, *Estimated Petroleum Finding Costs in Alberta, 1970-1983*, CERI Research Report 85-2 (Calgary, Alberta: Canadian Energy Research Institute, October 1985).

Chapter 3

LIMITATIONS OF THE ANALYSIS

Short-term and long-term replacement costs are analysed on an aggregate level in this study. Despite the relative simplicity of the two methodologies used, numerous difficulties are encountered when attempting to obtain aggregate estimates of either short-term or long-term replacement costs. The difficulties arise due to problems with both the methodologies and the available aggregate data; some of these problems are discussed in this chapter. The methodological problems are primarily related to the difficulty of determining methodologies that reflect the "average" exploration and development scenario for each of the two analyses. While aggregate expenditure and reserves data are readily available, data problems arise because the data (particularly for reserves) are often not disaggregated to the degree necessary for the analyses and are sometimes inaccurate.

3.1 Methodological Limitations

3.1.1 Expenditure Component

The main difficulties pertaining to the expenditure component of the analyses arise from the need to determine the expenditure categories that should be included in the calculations as well as the appropriate expenditure profiles.

The first problem concerns the need to include in the calculations all expenditures that result in reserves additions. The replacement cost estimates in this study are calculated under the assumption that reserves additions occur only due to exploration and development activity. However, the point at which development ends and production begins is somewhat arbitrary. And, to the extent that reserves additions are generated as a result of production/operating expenditures, some of those expenditures would belong in the analysis but are excluded. The replacement cost estimates could vary considerably depending on the expenditure components that are included in the calculations.

The second problem arises because the actual expenditure profile for reserves can vary considerably depending on factors such as the size of the pool, the geographic area and the discovery period.

Therefore, it is difficult to identify the profile which best reflects the "average" scenario.

3.1.2 Reserves Component

The main difficulty pertaining to the reserves component is the need to estimate the reserves additions generated due to exploration and development expenditures. The published reserves data provide estimates of annual reserves additions as well as estimates of reserves discovered in each year which reflect appreciation of the initial discovery. The first format provides the reserves estimates required for the analysis of short-term replacement costs. While the second format is that which is required to analyse long-term replacement costs, the published reserves estimates reflect only the appreciation that has occurred to date rather than full appreciation; this necessitates devising a method of estimating fully appreciated reserves (particularly for the most recent discovery years, for which including only the appreciation that has occurred to date would substantially underestimate fully appreciated reserves).

3.2 Data Limitations

3.2.1 Expenditure Component

The available aggregate expenditure data do not appear to pose any major problems for the replacement cost analyses. The main area of concern regarding expenditures is the need to use forecasted expenditures. Some uncertainty is introduced into the analysis any time forecasting is required.

3.2.2 Reserves Component

The major areas of concern regarding the aggregate reserves data are that some of the data are not presented in the form required for the analyses, thus making it difficult to match reserves additions with expenditures, and that reserves booking procedures can result in inaccurate reserves estimates.

The calculations of replacement costs require estimates of the reserves additions which resulted from exploration and development expenditures. If all reserves additions were generated as a result of upstream expenditures, determining the required reserves estimates from the aggregate data would be relatively easy. However, a portion of the reserves additions is the result of changes to factors other than expenditures, and it should therefore be excluded from the analysis

(such as reserves additions generated due to different measurement techniques being used or changes in economic conditions). Difficulties are encountered because it is not possible to isolate the portion of the revisions component of reserves additions that is due to expenditures alone.

Present booking procedures sometimes result in a discrepancy between the year in which reserves additions are obtained and the year in which they are booked. This results in the published estimates of annual reserves additions sometimes being inaccurate.

3.3 Implications of the Limitations

It should be recognized that replacement costs are estimated using imperfect methodologies and problematic data. For any particular year, it is not possible to determine the overall effect the limitations would have on the results. Hence, any estimates of replacement costs must be interpreted and applied carefully.

Some of the limitations encountered when the analyses are conducted on an aggregate level may be overcome by conducting the analyses using disaggregate data. It should be possible for an individual company to isolate the reserves data required for the analyses. In addition, analysis of case histories should provide valuable information.

The following two chapters discuss in detail the specific methodology used, the results obtained and the implications of the limitations presented above for the short-term and long-term replacement cost analyses.

Chapter 4

SHORT-TERM REPLACEMENT COSTS

4.1 Definition

In this study, short-term replacement costs refer to the per unit exploration and development costs incurred to obtain reserves additions in a particular year.

The short-term replacement costs are calculated as the sum of exploration and development expenditures from a particular year divided by the reserves additions from that year. The short-term replacement cost estimate for a given year is the present value of the per unit cost of obtaining reserves additions through exploration and development in that year.

4.2 Methodology

4.2.1 Data Sources

4.2.1.1 Expenditures

The expenditure data are taken from the Canadian Petroleum Association (CPA) Statistical Handbook. Exploration expenditures comprise expenditures on geological and geophysical analysis, exploration drilling, and land acquisitions and rentals; development expenditures include expenditures on development drilling, field equipment, secondary recovery and pressure maintenance, natural gas plant construction, and other development-related items or activities. In this study, with the exception of expenditures on natural gas plant construction, all expenditures which have been categorized by the CPA as exploration or development expenditures have been included in the analysis.[1] It should be noted that the relevant overhead expenditures are included in the expenditure estimates. The current dollar net cash expenditures for Alberta and Saskatchewan are presented in Tables A.1 to A.5.

The annual net cash expenditures are converted to 1988 constant dollars by using cost escalation rates developed by the Canadian Petroleum Association (see Table A.6). There is no cost escalation rate specifically for either land expenditures or "other" development

expenditures; at the suggestion of the CPA, these expenditures are converted to constant dollars using the drilling expenditure escalation rate and the GDP deflator, respectively. Although cost escalation rates have only been developed for Alberta, the rates have also been applied to Saskatchewan. Provincial government representatives have indicated that although the expenditure levels are different from those in Alberta, it is reasonable to assume that the rate at which expenditures are increasing is the same. The constant dollar net cash expenditures for the two provinces are presented in Tables A.7 to A.11.

4.2.1.2 Reserves Additions

The reserves additions data for crude oil and marketable natural gas are taken from the provincial reserves books that are published annually.[2] The calculation of short-term replacement costs requires an estimate of the reserves additions generated by exploration and development expenditures. These reserves additions are included in categories such as discoveries, extensions, revisions, drilling, and development and re-evaluation. For Saskatchewan, since estimates of marketable gas reserves are not published, the advice of provincial government representatives was obtained to determine the best way to estimate marketable gas reserves additions from the published gas reserves data.[3] (The reserves additions for Alberta and Saskatchewan are presented in Tables A.12 and A.13, respectively.)

4.2.2 Hydrocarbons for which Short-Term Replacement Costs are Calculated

4.2.2.1 Crude Oil Equivalent

Expenditure data are published for the petroleum industry, rather than for individual hydrocarbons. The short-term replacement cost per barrel of crude oil equivalent can be calculated by matching these expenditures with an aggregate estimate of crude oil and natural gas reserves. Natural gas reserves are converted to crude oil equivalent by using an average historical wellhead price equivalence of 11.8 thousand cubic feet of natural gas per barrel of crude oil (see Table A.21).[4]

4.2.2.2 Crude Oil and Natural Gas

Since expenditures are not available for individual hydrocarbons, short-term replacement costs can only be calculated for crude oil and natural gas separately by apportioning the expenditures between them. The proportion of successful exploratory metres drilled

which found oil is used as a proxy for crude oil exploratory intent to apportion exploration expenditures.[5] A similar calculation is done using development metres drilled to determine a proxy for crude oil development intent to apportion development expenditures. In both cases, the remaining proportion of total successful metres drilled represents natural gas intent.[6,7,8] (The crude oil intent ratios are presented in Table A.22.)

4.2.3 Alternative Scenarios for Calculating Short-Term Replacement Costs

The results obtained from an analysis of short-term replacement costs could vary considerably under different assumptions. In this study, these costs are calculated under two different scenarios. Both scenarios use expenditure data that are adjusted according to the set of assumptions discussed below. Different results are generated from the two scenarios because different reserves estimates are used in the calculations. Base case results are obtained by adjusting the reserves data, while unadjusted case results are obtained by using the published reserves data with no adjustments made.

4.2.3.1 Base Case

Base case estimates of short-term replacement costs are calculated by adjusting both the expenditure and reserves data.

The expenditure data are adjusted to reflect the time lags between when expenditures are made and when reserves additions generated by those expenditures occur. Of the exploration expenditure components, land expenditures and geological and geophysical expenditures are lagged by two years and one year, respectively, while exploratory drilling expenditures are not lagged. None of the development expenditure components are lagged.[9]

The reserves data are adjusted in order to mitigate some of the problems encountered when using aggregate reserves estimates for this analysis. The major difficulty pertains to isolating the reserves additions that are generated as a result of exploration and development expenditures rather than due to other factors. (This difficulty was mentioned in Chapter 3.)

The only analysis for which the published data are presented in the required form (that is, discoveries and reserves additions due to development are identified separately) is that of Alberta crude oil for the period 1985 to 1988.[10] Thus, base case results are

presented only for this time period. The other reserves estimates are adjusted according to the suggestions of provincial government representatives.[11] Because gas reserves data are not available in the required form, results have been obtained for Saskatchewan gas by using the unadjusted reserves estimates.[12]

4.2.3.2 Unadjusted Case

Short-term replacement cost estimates for the unadjusted case are calculated by making the same adjustments to the expenditure data as in the base case, but using the reserves data as published. In order to use consistent data series, results from this analysis are provided for the period 1979-1988.[13]

4.3 Short-Term Replacement Cost Estimates

The short-term replacement cost estimates are presented in Tables B.1 and B.2 and in Figures 4.1 and 4.2 for Alberta and Saskatchewan, respectively.

4.3.1 Base Case Results

Base case estimates of short-term replacement costs for crude oil equivalent in 1988 are $8.94 and $4.70 per barrel of oil equivalent (BOE) for Alberta and Saskatchewan, respectively.

The corresponding estimates of short-term replacement costs for crude oil and marketable natural gas in 1988 are $9.16 and $4.42 per barrel for crude oil, and $0.72 and $0.47 per thousand cubic feet (Mcf) (or $8.54 and $5.59 per BOE) for marketable natural gas.

4.3.2 Unadjusted Case Results

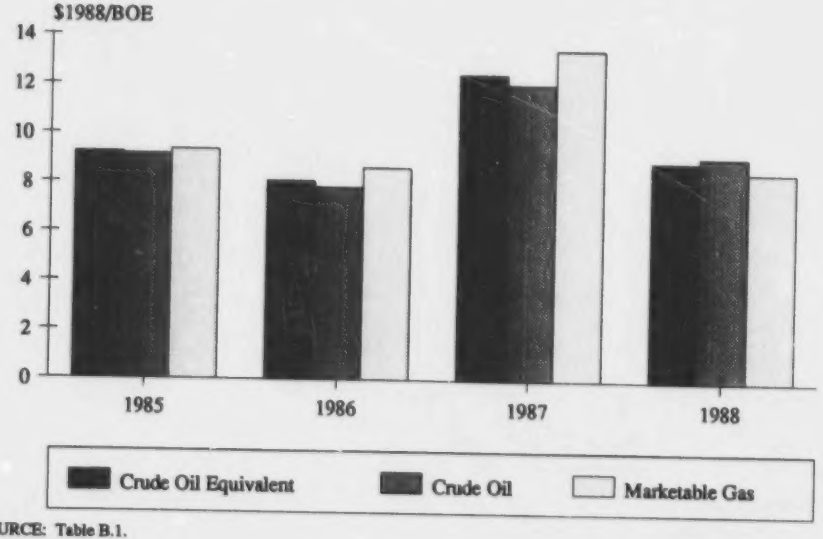
Unadjusted case estimates of short-term replacement costs for crude oil equivalent in 1988 are $10.90 and $3.44 per BOE for Alberta and Saskatchewan, respectively.

The corresponding estimates of short-term replacement costs for crude oil in 1988 are $13.09 and $2.98 per barrel. The estimates of short-term replacement costs for marketable natural gas in 1988 are $0.70 and $0.47 per Mcf (or $8.29 and $5.59 per BOE).

4.3.3 Interprovincial Comparisons of Results

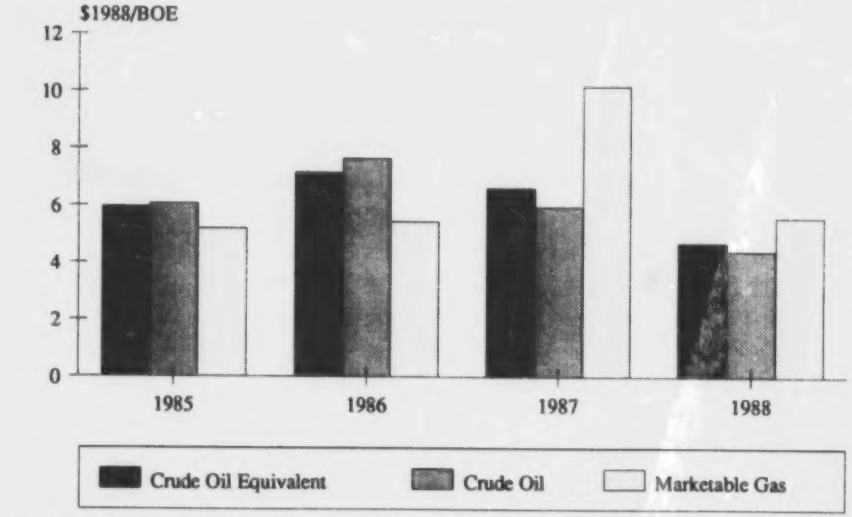
The estimates of short-term replacement costs for Saskatchewan are noticeably lower than the corresponding estimates for

Figure 4.1
Alberta Base Case
Short-Term Replacement Costs



SOURCE: Table B.1.

Figure 4.2
Saskatchewan Base Case
Short-Term Replacement Costs



SOURCE: Table B.2.

Alberta for each of crude oil equivalent, crude oil, and marketable natural gas. It is important that the relative cost estimates be viewed in the proper perspective.

According to Saskatchewan government representatives, factors that contribute to the relatively lower replacement costs for Saskatchewan include higher success ratios, lower cost shallow drilling, a greater proportion of development drilling, and relatively lower land costs.

It should be recognized, however, that there are other significant factors relevant to investment decision making that may inhibit higher activity levels in Saskatchewan despite the lower replacement costs. For instance, operating expenditures, which are not included in the analysis, represent a higher proportion of total expenditures in Saskatchewan than in Alberta. As well, Saskatchewan's oil generally tends to be of lower quality than that in Alberta and thus receives a lower price. Since investment decisions are based on a complete analysis of expected costs and revenues, this analysis of replacement costs could provide misleading information unless the expected higher additional costs and the expected lower revenues in Saskatchewan are also considered.

The inclusion of operating costs and relative values of the hydrocarbon reserves could reveal a situation which is quite different from that which the results of the analysis indicate. While the exact magnitude of the change that would occur with a complete analysis is not known, the inclusion of these two factors would certainly reduce the advantage indicated for Saskatchewan.

4.4 Analysis of the Results

4.4.1 Interpretation of the Results

The purpose of the methodology is to estimate the per unit cost of obtaining hydrocarbon reserves through exploration or development. The short-term replacement cost estimates presented in this study represent the present value of the exploration and development expenditures attributed to a unit of reserves additions obtained in each year. Readers should be cautious if these cost estimates are to be used in short-term cash flow analyses. Many of the reserves additions obtained in a particular year would not be available for production without incurring considerable additional costs. Hence, it is not appropriate to simply compare the current cost estimates presented in this study with current prices. The importance of this consideration

would depend in part on the proportions of reserves additions that are discoveries due to exploration expenditures and other additions due to development expenditures.

These short-term replacement cost estimates represent the weighted average of the costs of obtaining reserves additions through exploration and development activity for each year.[14] If the per unit cost of obtaining reserves additions through exploration is different from that for development, then the short-term replacement cost estimates would be influenced by the relative proportions of expenditures on exploration and development. Hence, it would be of interest to estimate the separate finding cost and development cost components, and to try to analyse changes in short-term replacement cost estimates in terms of changes in relative expenditure levels. However, due to problems with present booking procedures, it was recommended that the gross additions not be separated into the individual components.

It is important to recognize limitations related to the comparison of short-term replacement cost estimates for Alberta and Saskatchewan. These results were obtained by using different data sources: CPA expenditure data were used in both analyses, but the reserves data are from the respective provincial governments. Differences in the reserves definitions used, in the data collection methods, or in any other factors related to data collection, would generate incomparable results.

4.4.2 Limitations of the Results

Use of the short-term replacement cost methodology requires that exploration and development expenditures made in a particular year be matched with the reserves additions that they generate in that year. As indicated in Chapter 3, there may be problems with the replacement cost results due to the numerous limitations of the analysis.

One potential problem is related to the inability to isolate the portion of the revisions component of reserves additions which is due to factors other than expenditures. Although adjustments are made to the reserves estimates in the base case, it should be recognized that any such adjustments are ad hoc. Thus, the adjusted reserves estimates may not be accurate estimates of the reserves additions required for the analysis, and could therefore generate inaccurate replacement cost estimates. The importance of this problem depends on the relative contributions of expenditures and other factors to the

revisions component of reserves additions; however, this would change from year to year, making it difficult to apply an appropriate adjustment factor.

Another potential problem is related to the present reserves booking procedures. Of particular concern is the time lag between when information about reserves is acquired and when this information is booked. For example, for gas reserves, the Energy Resources Conservation Board uses the end of October as the cut-off point for the inclusion of new discoveries in that year's reserves estimates. Any gas discoveries made in November and December would not be recorded as discoveries; rather, they would be recorded as part of the "development and re-evaluation" component of the following year's reserves additions (because they were not discoveries in the following year but did have to be reflected in the reserves estimates). If the volume of gas discoveries made in November and December is fairly constant from year to year then this would not present a problem for the sum of the discoveries and development and re-evaluation components (and hence would not affect the short-term replacement cost estimates), but the estimates of the individual components would be suspect. However, since the volume of gas discoveries varies when factors such as oil prices and the size of exploration budgets change, it is likely that the delay in booking discoveries would result in inaccurate short-term replacement cost estimates.

Finally, it should be recognized that the short-term replacement costs are estimated using what must be considered preliminary reserves estimates. The reserves estimates used are historical, with any revisions made to previous reserves estimates being attributed in the data series to expenditures made in the year in which the revisions occur, rather than being allocated back to the initial estimate. As the initial reserves estimates are made with the least information, they may be quite inaccurate and could provide misleading short-term replacement cost estimates.

Footnotes

[1]Natural gas plant construction expenditures are excluded due to difficulties in matching expenditures with the appropriate reserves additions. Since at least some of these expenditures belong in the analysis, it should be recognized that this exclusion would tend to underestimate the short-term replacement costs for marketable natural gas.

[2]Alberta Energy Resources Conservation Board, *Alberta's Reserves of Crude Oil, Oil Sands, Gas, Natural Gas Liquids, and Sulphur*, ERCB ST89-18 (Calgary, Alberta: Energy Resources Conservation Board, December 1988); Saskatchewan Energy and Mines, *Reservoir Annual*, (Saskatchewan: Saskatchewan Energy and Mines, 1979-1988).

[3]Saskatchewan publishes reserves estimates for the categories of non-associated, associated, and dissolved gas. It was recommended that marketable gas reserves estimates be calculated by including 95 percent of the non-associated and associated gas estimates and 100 percent of the dissolved gas estimates.

[4]This conversion factor is the average historical wellhead price equivalence for Alberta. Although the corresponding number for Saskatchewan is different, it is desirable to use a constant conversion factor. The conversion factor for Alberta was used because of the relative magnitude of the Alberta industry and also because the factor of 11.8 is quite realistic for Saskatchewan in the past few years.

[5]One potential problem with this method is that when oil is found, all of the associated costs are allocated to oil; it may be more appropriate for some of the costs to be allocated to the associated and solution gas found at the same time. In this case, too high a proportion of the costs would be allocated to oil, implying that costs associated with oil would be overestimated and costs associated with natural gas would be underestimated. This is probably more relevant to exploratory intent than to development intent.

[6]Since the proxies for exploratory intent and development intent are calculated using only successful metres drilled, there is an implicit assumption that the same proportions of unsuccessful metres drilled are attributable to crude oil and natural gas.

[7]The crude oil and natural gas intent ratios are applied to all expenditure components with the exception of expenditures on secondary recovery and pressure maintenance which are allocated entirely to crude oil.

[8]Expenditures made to obtain natural gas reserves generate raw gas, which is then separated into marketable gas and by-products. Using reasoning analogous to that used to determine the crude oil and natural gas intent ratios, it is assumed that firms make expenditures to obtain marketable gas rather than by-products; hence, all expenditures that are allocated to natural gas are attributed to the marketable

gas reserves estimates. Since this has the effect of matching all relevant expenditures with only some of the resulting reserves additions, it should be recognized that this would tend to overestimate the short-term replacement costs for marketable natural gas. A complete evaluation of the economics of natural gas activity should include in the analysis all revenues and costs associated with marketable natural gas, as well as with the by-products. This factor is expected to become of increasing importance as the proportion of sour gas found increases.

[9]It may be more appropriate to lag some individual components of development expenditures, such as the field equipment component, but this seems to be an unnecessary complication in light of the problems encountered in trying to match expenditures and reserves.

[10]Even these Alberta crude oil reserves estimates are flawed due to reasons such as the booking procedures used, but no further adjustments are made due to the inability to isolate the problems.

[11]Alberta marketable natural gas reserves estimates are adjusted by excluding the revisions that were made as the result of a review of small gas pools. Saskatchewan crude oil reserves estimates are adjusted by determining the net revisions for the 1979-1988 time period and allocating them in equal portions to each year in that time period; this adjustment would smooth the effects of non-expenditure related revisions.

[12]Base case results are obtained by isolating, and then adjusting, the revisions component of the reserves additions. However, it is not possible to isolate the marketable natural gas revisions for Saskatchewan. Thus, results could only be obtained by making a purely ad hoc adjustment which would necessarily affect both revisions and other reserves additions. Any results obtained from such an adjustment would be very unreliable because the proportion of reserves additions that is due to revisions likely changes from year to year. Therefore, the base case analysis for Saskatchewan uses the unadjusted estimates of marketable natural gas reserves additions.

[13]Short-term replacement costs are calculated using the following general formula:

$$STRC_t = [L_{t-2} + GG_{t-1} + EDR_t + DEV_t]/RESADD_t$$

where:
- STRC = the short-term replacement cost,
- L = land expenditures,
- GG = geological and geophysical expenditures,
- EDR = exploratory drilling expenditures,
- DEV = development expenditures, and
- RESADD = total reserves additions.

In the base case analysis, adjusted estimates of annual reserves additions are used; in the unadjusted case, the published estimates of annual reserves additions are used.

[14]The following formula illustrates how the finding cost and development cost components are weighted:

$$STRC_t = [FC_t \times (DISC_t/RESADD_t)] +$$

$$[DC_t \times (RESADD_t - DISC_t)/RESADD_t]$$

where:
- STRC = the short-term replacement cost,
- FC = the per unit cost of obtaining reserves additions due to exploration expenditures (i.e., $FC_t = (L_{t-2} + GG_{t-1} + EDR_t)/DISC_t$)
- DC = the per unit cost of obtaining reserves additions due to development expenditures (i.e., $DC_t = DEV_t/(RESADD_t - DISC_t)$),
- DISC = the volume of discoveries, and
- RESADD = the total reserves additions.

Chapter 5

LONG-TERM REPLACEMENT COSTS

5.1 Definition

In this study, long-term replacement costs refer to the per unit costs incurred during the exploration and development stages of the upstream cycle for particular reserves.

The long-term replacement costs are calculated as the sum of all exploration and development expenditures associated with reserves discovered in a given year, divided by the fully appreciated reserves from that discovery year. The long-term replacement cost estimate for a given year is the present value of the per unit exploration and development expenditures related to the reserves discovered in that year.

5.2 Methodology

5.2.1 Data Sources

An analysis of long-term replacement costs has been conducted for Alberta only, due to a lack of adequate reserves data for Saskatchewan.

5.2.1.1 Expenditures

The analysis requires the use of both historical and forecasted expenditure data. The historical expenditures are taken from the CPA Statistical Handbook. The exploration expenditures are entirely historical; the development expenditures are partly historical and partly forecasted, with development expenditures for the period 1989 to 1993 assumed to be $2200 million annually (in 1988 constant dollars).[1] The current dollar net cash expenditures for Alberta are presented in Tables A.1, A.2 and A.5.

The expenditure categories are the same as those used for the short-term replacement cost analysis. The historical expenditures are converted to 1988 constant dollars by using cost escalation rates developed by the CPA (see Table A.6). The constant dollar net cash expenditures for Alberta are presented in Tables A.7, A.8 and A.11.

5.2.1.2 Fully Appreciated Reserves

Estimates of fully appreciated reserves are determined from the CPA's estimates of initial established reserves dated back to the year of discovery. The reserves estimates for each discovery year are revised annually to reflect both further appreciation that has occurred and revisions due to better geologic and engineering information and changes in economic conditions. Depending on how recently the reserves were discovered relative to the development profile of the reserves, some of the reserves estimates would reflect full appreciation while others, particularly for the more recent discovery years, would reflect only partial appreciation. The latter group would require that an appreciation factor be applied to obtain an estimate of fully appreciated reserves for the discovery year.[2]

The reserves development profile used in this analysis is based on the methodology used in the previous finding cost studies: it is assumed that reserves are developed in the five years following discovery, after which time they are assumed to be fully appreciated.[3] Therefore, in this analysis, any reserves estimates for discovery years prior to 1984 are assumed to reflect full appreciation, while reserves estimates for discovery years 1984 to 1988 are expected to appreciate further and thus have an appreciation factor applied to them to account for the expected future appreciation.

The current CPA estimates of reserves from the various discovery years, and the corresponding estimates of fully appreciated reserves, are presented in Table A.20. Tables A.14 to A.19 describe the calculation of appreciation rates used to estimate fully appreciated crude oil and marketable natural gas reserves.

5.2.2 Hydrocarbons for which Long-Term Replacement Costs are Calculated

5.2.2.1 Crude Oil Equivalent

As in the short-term replacement cost methodology, the crude oil and natural gas reserves must be aggregated in order to match them with the available aggregate estimate of industry expenditures. The conversion factor of 11.8 thousand cubic feet of natural gas per barrel of crude oil is also employed in this analysis.

5.2.2.2 Crude Oil and Natural Gas

Long-term replacement costs are calculated for crude oil and natural gas separately by apportioning the aggregate industry expenditures between them. As in the short-term replacement cost methodology, the proportions of successful exploratory and development metres drilled which found oil are used as proxies for crude oil exploratory intent and crude oil development intent, respectively. The remaining proportions of total successful metres drilled represent the corresponding natural gas intent.

5.2.3 Alternative Scenarios for Calculating Long-Term Replacement Costs

Finding costs as well as long-term replacement costs are calculated for crude oil equivalent, crude oil, and marketable natural gas for Alberta.

The results obtained from an analysis of long-term replacement costs can vary considerably depending on the assumptions used. In this study, results are obtained from the analysis under two different scenarios. Both scenarios employ reserves estimates that are adjusted to reflect full appreciation, as required by the model. The individual components of exploration and development expenditures are lagged to reflect the exploration and development profile of the reserves from a particular discovery year. Different results are generated from the two scenarios due to the differences in the expenditure data used in the calculations. Base case results are obtained from conducting the analysis using lagged exploration expenditure data, while unadjusted case results are obtained by using the exploration expenditure data as published.

The long-term replacement cost estimates can easily be broken down into their separate finding cost and development cost components. For both the base case and the unadjusted case, yearly estimates, as well as three-, five-, and seven-year moving average estimates, are presented for finding costs and for long-term replacement costs. As indicated in Chapter 3, there are problems with some of the aggregate reserves estimates. Although the use of moving averages does not eliminate the problems, it does reduce the volatility that occurs because of them.[4]

5.2.3.1 Base Case

Base case long-term replacement cost estimates are calculated by matching the expenditure data, which is adjusted according to the assumptions outlined below, with the estimates of fully appreciated reserves.

The individual expenditure components are lagged to reflect the exploration and development profile of reserves from a particular discovery year. The land and geological and geophysical expenditure components of exploration expenditures are lagged by two years and one year, respectively, while exploratory drilling expenditures are not lagged. It is assumed that reserves become fully appreciated in the five years following discovery; development expenditures are allocated to reflect this development profile.[5,6,7]

5.2.3.2 Unadjusted Case

Long-term replacement costs are estimated in the unadjusted case by using the unadjusted expenditure data with the fully appreciated reserves estimates.[8]

5.3 Long-Term Replacement Cost Estimates

5.3.1 Base Case Results

5.3.1.1 Crude Oil Equivalent

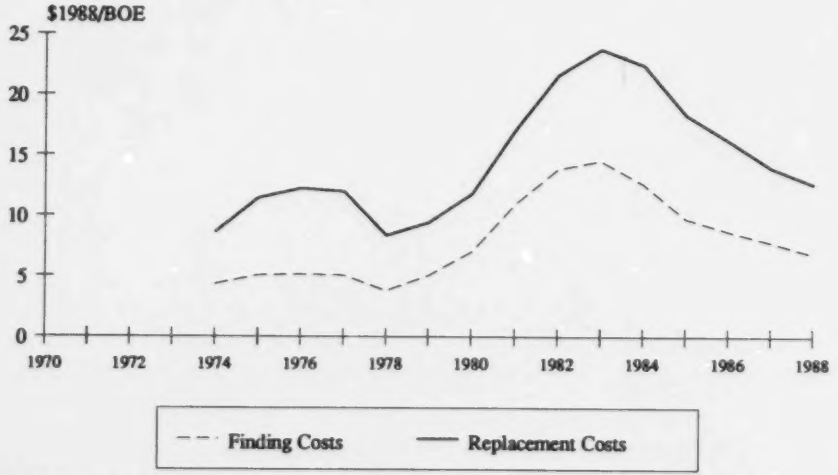
Finding Costs

The crude oil equivalent finding costs are presented in Table C.1. The three-year moving average estimate of finding costs in 1988 is $6.85 per BOE. Figure 5.1 indicates that crude oil equivalent finding costs have been on a downward trend since the early 1980s.

Long-Term Replacement Costs

Figure 5.1 shows that the long-term replacement costs for crude oil equivalent exhibit a trend similar to that of finding costs. In the 1980s, the long-term replacement cost estimates (see Table C.2) have generally been slightly less than double the finding cost estimates, with a three-year moving average estimate for 1988 of $12.69 per BOE.

Figure 5.1
Alberta Base Case - Crude Oil Equivalent
Long-Term Replacement Costs



SOURCES: Tables C.1 and C.2.

NOTE: Three-year moving averages.

5.3.1.2 Crude Oil

Finding Costs

The crude oil finding costs presented in Table C.3 show a general declining trend in the 1980s. As shown in Figure 5.2, however, the trend has been somewhat unstable over that time period. The three-year moving average estimate for 1988 is $8.17 per barrel.

Long-Term Replacement Costs

Figure 5.2 indicates that the three-year moving average estimates of long-term replacement costs for crude oil have been declining steadily since 1983; this trend is more pronounced than that of crude oil finding costs. The three-year moving average estimate (as shown in Table C.4) is $17.28 per barrel in 1988.

5.3.1.3 Marketable Natural Gas

Finding Costs

Marketable natural gas finding costs are presented in Tables C.5 and C.7. Figures 5.3 and 5.4 indicate a steady and pronounced downward trend in these costs since the early 1980s. The three-year moving average estimate of marketable natural gas finding costs in 1988 is $0.47 per Mcf (or $5.55 per BOE).

Long-Term Replacement Costs

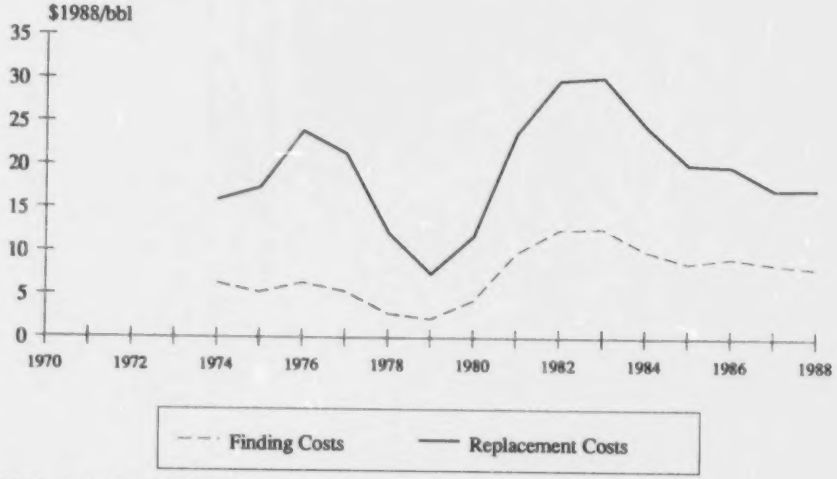
As indicated in Figures 5.3 and 5.4, long-term replacement costs for marketable natural gas have also exhibited a steady and pronounced downward trend in recent years. The three-year moving average estimate of long-term replacement costs for the 1988 discovery year is $0.70 per Mcf (or $8.24 per BOE).

5.3.2 Unadjusted Case Results

Finding Costs

When the unadjusted data are used to calculate finding costs, the 1988 three-year moving average estimates are $5.84 per BOE for crude oil equivalent, $6.62 per barrel for crude oil, and $0.43 per Mcf (or $5.10 per BOE) for marketable natural gas (see Tables C.9, C.11, C.13 and C.15).

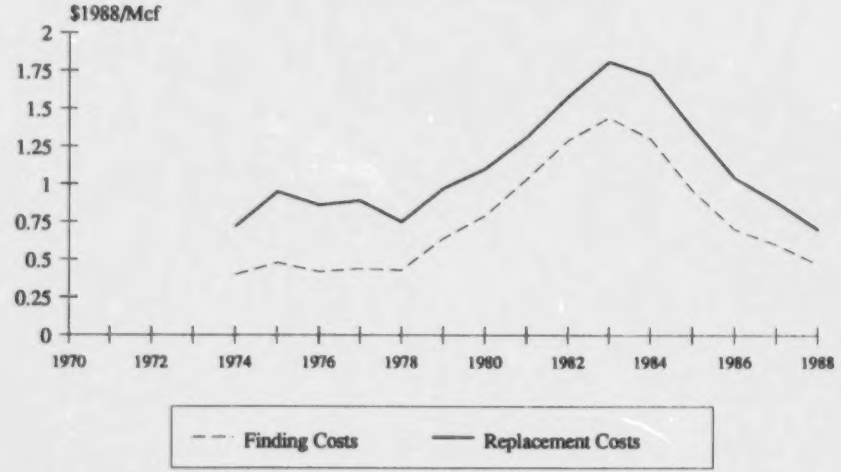
Figure 5.2
Alberta Base Case - Crude Oil
Long-Term Replacement Costs



SOURCES: Tables C.3 and C.4.

NOTE: Three-year moving averages.

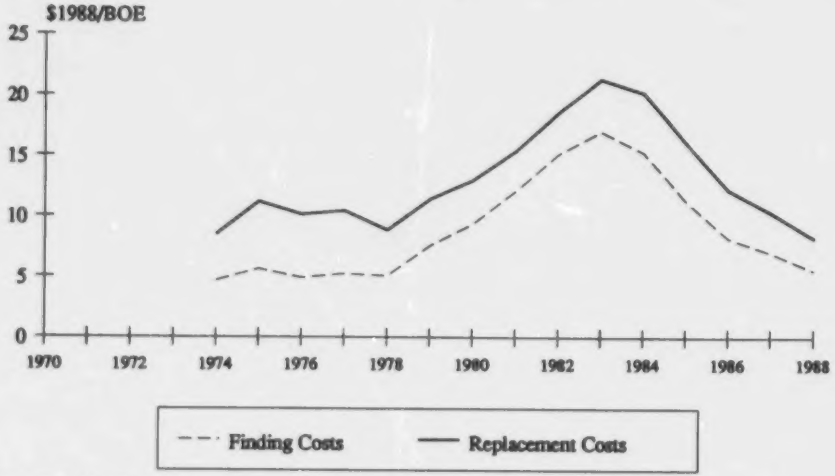
Figure 5.3
Alberta Base Case - Marketable Gas
Long-Term Replacement Costs



SOURCES: Tables C.5 and C.6.

NOTE: Three-year moving averages.

Figure 5.4
Alberta Base Case - Marketable Gas
Long-Term Replacement Costs



SOURCES: Tables C.7 and C.8.

NOTE: Three-year moving averages.

As Figure 5.5 shows, the downward trend since the early 1980s is clearly evident for crude oil equivalent, crude oil and marketable natural gas finding costs. These finding cost trends are similar to those found in the base case; the levels of finding costs are different, as expected, because the different sets of assumptions regarding the lagging of individual components of exploration expenditures change the expenditures used in the calculations.

Long-Term Replacement Costs

Unadjusted data provide three-year moving average estimates of long-term replacement costs for 1988 of $11.69 per BOE for crude oil equivalent, $15.74 per barrel for crude oil, and $0.66 per Mcf (or $7.78 per BOE) for marketable natural gas (see Tables C.10, C.12, C.14 and C.16). Figure 5.6 illustrates trends for these long-term replacement costs that are similar to the finding cost trends, as well as to the base case long-term replacement cost trends.

5.4 Analysis of the Results

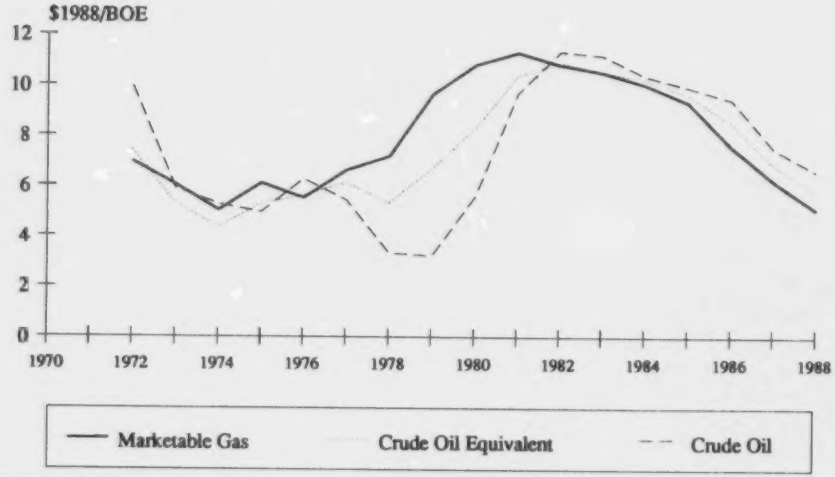
5.4.1 Interpretation of the Results

The purpose of the methodology is to estimate the per unit cost of finding and developing hydrocarbon reserves. The long-term replacement cost estimates presented in this study represent the present value of the exploration and development expenditures attributed to a unit of reserves from the various discovery years.[9] Such cost estimates should be useful for strategic planning and making long-term investment decisions. It should be recognized, however, that a complete analysis requires further information about additional costs incurred during the energy cycle (i.e., production/operating costs) and about the revenue generated from the reserves. This would enable a comparison of per unit full cycle cost estimates[10] with per unit revenues to determine the economics of oil and gas activity.

These long-term replacement cost estimates represent the sum of the finding cost and the development cost for the reserves. It is possible, therefore, to break down the long-term replacement cost estimates into their separate finding cost and development cost components.[11]

Finding costs and long-term replacement costs, and the trends in these costs, are affected by a number of factors, thus making it difficult to identify the exact cause of any changes that occur. The

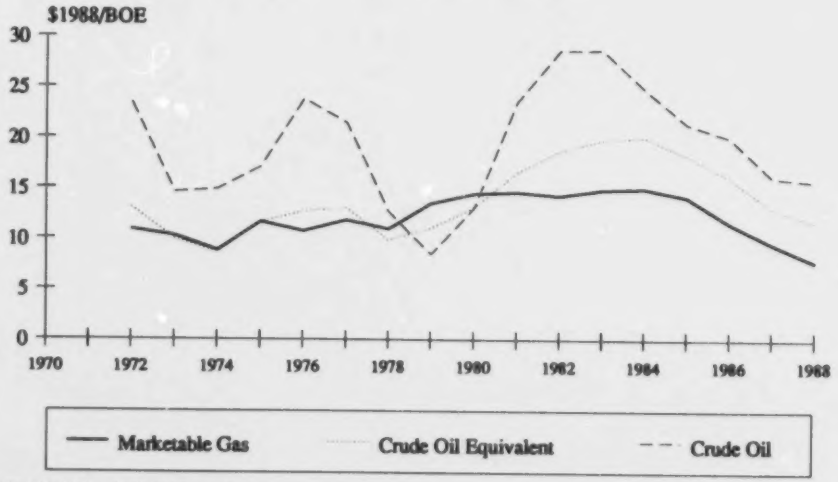
Figure 5.5
Alberta Unadjusted Case
Finding Costs



SOURCES: Tables C.9, C.11 and C.15.

NOTE: Three-year moving averages.

Figure 5.6
Alberta Unadjusted Case
Long-Term Replacement Costs



SOURCES: Tables C.10, C.12 and C.16.

NOTE: Three-year moving averages.

declining trends in finding costs and long-term replacement costs over the last few years are somewhat counter-intuitive: these costs are expected to increase over time due to the depletion effect. A decline in the number of large pool discoveries (particularly in the case of crude oil) has been observed. However, the effect of this factor seems to have been more than offset in recent years by factors which would tend to reduce costs, including improved technology, increased competition in the service industry, smaller budgets for exploration and development which would lead to only the most promising prospects being pursued, and growth in reserves additions (particularly for natural gas). The direction of the change in costs from one year to the next depends in part on the relative magnitudes of these competing forces. Due to the methodological and data limitations inherent in an aggregate analysis (as were identified in Chapter 3 and are discussed further below), it is recommended that the cost estimates obtained from such an analysis be used only to obtain information about general trends rather than to ascertain annual cost estimates.

5.4.2 Limitations of the Results

The methodological and data limitations encountered with the analysis of long-term replacement costs can greatly influence the results obtained. A few of the limitations are discussed below.

The inability to isolate revisions which occur due to expenditures is a potential problem for this analysis. Long-term replacement costs are estimated by using the annually revised reserves estimates for the various discovery years. These revised estimates reflect the appreciation which has occurred due to development expenditures, but they also reflect revisions caused by other factors which are not related to reserves appreciation. It is not possible to isolate the effect of expenditures on the reserves estimates, thus making it impossible to obtain an accurate estimate of the appreciation rate to be used in the calculation of fully appreciated reserves and of long-term replacement costs.

As mentioned above, the long-term replacement cost methodology uses the most recent reserves estimates which include revisions made over time. The cost estimates for a particular discovery year are likely to become more reliable the further the year is in the past because the reserves estimate should more accurately reflect the true magnitude of the reserves.[12] Unfortunately, this implies that since the results for the most recent discovery year are based on only the initial estimate of reserves discovered in that year, the cost

estimates for the most recent discovery year, and the trends in such costs over the last few years, are the least reliable.

The present booking procedures also present difficulties for the analysis of long-term replacement costs. Although it is not readily apparent from the aggregate reserves data, there are numerous problems with obtaining a reliable estimate of the appreciation rate from the published data. The problem mentioned in previous sections regarding the time lag between when reserves are discovered and when reserves are booked is also a concern for this analysis: discoveries are often underestimated for the discovery year and the appreciation from that year to the next is then overestimated, thus also overestimating the appreciation rate. Such a situation arose recently with the major gas discovery at Caroline: the reserves were discovered in 1986 but were not booked until 1987. The CPA's estimate of marketable natural gas initial established reserves discovered in 1986 changed from 9492 million cubic metres in the 1986 edition of the CPA Statistical Handbook to 32 083 million cubic metres in the 1987 edition. In this analysis, the difference between the two estimates is attributed to appreciation of the initial estimate when, in fact, some of the difference should be included in the initial estimate of reserves discovered in 1986, resulting in much lower appreciation of the initial estimate.

Another problem relates to reserves which are discovered but not booked until many years later when the reserves become economic: when the reserves are eventually booked, they are allocated to the discovery year, sometimes resulting in significant revisions to reserves estimates for those discovery years. This would certainly change the estimate of long-term replacement costs for that particular discovery year, and may even change the trend in those costs in the relevant time period. The opposite effect could be experienced if development indicates that what was thought to be a separate pool is actually found to be part of a pool discovered in a previous year, thus reducing the reserves estimate for the later year. In either case, these revisions would be attributed to expenditures made many years ago when, in fact, they occurred due to recent expenditures. In these situations, the current methodology would not accurately match expenditures and reserves additions.

For any particular year, it is not possible to determine the overall effect on the results of the numerous limitations of the analysis. Thus, neither the magnitude nor the direction of the error in the yearly long-term replacement cost estimates can be determined. The use of

moving averages can achieve some success at providing better matches of expenditure and reserves data; however, a moving average of a set length of time would be unable to capture the varied, and often lengthy, time periods affected by revisions to reserves estimates.

Footnotes

[1]The average level of development expenditures (including only the expenditure components used in the replacement cost analyses) was approximately $2200 million annually for 1984 to 1988. This is assumed to be a reasonable estimate of future development expenditures.

[2]In the CPA Statistical Handbook, "initial established reserves" are defined as: "established reserves prior to the deduction of any production"; "established reserves" are defined as "those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing or production, plus that judgement portion of contiguous recoverable reserves that are interpreted to exist, from geological, geophysical or similar information, with reasonable certainty."

The CPA estimates of initial established reserves include proved reserves as well as some portion of probable reserves. Reserves appreciation occurs when the reserves estimates are revised to include probable reserves that were not included in the previous reserves estimates.

[3]See Michele McLachlan, *Oil and Gas Finding Costs in Alberta: 1970-1987* (Calgary, Alberta: Canadian Energy Research Institute, Research Report 89-1, May 1989).

[4]Note that the moving averages are attributed to the last year included in the calculation in order to provide a result for 1988. Thus, the yearly cost estimates from 1986, 1987 and 1988 are used to calculate the 1988 three-year moving average.

[5]A five-year development profile implies that a portion of development expenditures from each of the first five years after discovery should be attributed to the reserves from that discovery year. The coefficients for the development expenditures are determined from the proportion of appreciation that occurs in the different years of the development profile.

[6]It is assumed that all components of the development expenditures made in a particular year are attributable to reserves from the same discovery years. While it may be more appropriate to lag some individual components of development expenditures, that seems to be an unnecessary complication in light of the data problems identified in Chapter 3.

[7]In the base case, long-term replacement costs are calculated using the following general formula:

$$LTRC_t = [L_{t-2} + GG_{t-1} + EDR_t + (a \times DEV_{t+1}) + (b \times DEV_{t+2}) + (c \times DEV_{t+3}) + (d \times DEV_{t+4}) + (e \times DEV_{t+5})]/FARES_t$$

where: LTRC = the long-term replacement cost,
L = land expenditures,
GG = geological and geophysical expenditures,
EDR = exploratory drilling expenditures,
DEV = development expenditures,
FARES = fully appreciated reserves for the particular discovery year, and
a, b, c, d, e = the coefficients for the development expenditures.

[8]In the unadjusted case, the long-term replacement costs are calculated using the general formula presented in the footnote above, except that no lags are used on the individual components of exploration expenditures.

[9]It should be remembered that the natural gas plant construction costs have not been included in the calculations; since at least some of these expenditures belong in the analysis, this would tend to underestimate the long-term replacement costs for marketable natural gas. In addition, since the analysis uses marketable, rather than raw, natural gas reserves, it attributes all gas-related expenditures to only some of the reserves additions generated; this would tend to overestimate the cost estimates for marketable natural gas.

[10]It should be noted that the term "replacement cost" is sometimes used to refer to the full-cycle cost estimates rather than to the cost estimates obtained by including only exploration and development expenditures.

[11]The long-term replacement cost is the sum of the costs of finding and developing reserves.

$$LTRC_t = FC_t + DC_t$$

where: LTRC = the long-term replacement cost,
FC = the per unit cost of finding reserves (i.e., $FC_t = (L_{t-2} + GG_{t-1} + EDR_t)/FARES_t$), and
DC = the per unit cost of developing reserves (i.e., $DC_t = [(a \times DEV_{t+1}) + (b \times DEV_{t+2}) + (c \times DEV_{t+3}) + (d \times DEV_{t+4}) + (e \times DEV_{t+5})]/FARES_t$).

[12]The time lag after which the reserves estimate for a discovery year stabilizes can vary substantially and the lag can be quite long, especially if EOR techniques are applied to reserves for which the initial estimates did not reflect the availability of such techniques.

Chapter 6

CONCLUSION

This study has attempted to clarify the issue of replacement costs by addressing it from two perspectives. In this study, "short-term replacement costs" refer to the per unit costs incurred to obtain reserves additions through exploration or development activity in a particular year. "Long-term replacement costs" refer to the per unit costs incurred during the exploration and development stages of the upstream cycle for particular reserves. Very different results are expected from the two methodologies because the short-term replacement cost estimates represent the weighted average of the finding cost and development cost components for the **reserves additions from a particular year**, whereas the long-term replacement cost estimates represent the sum of the finding cost and development cost components for the **fully appreciated reserves from a particular discovery year**.

As shown in Chapters 4 and 5, the different methodologies which correspond to the two interpretations of "replacement costs" match expenditures and reserves additions differently and thus generate different results which have different meanings. Comparisons of the short-term and long-term replacement cost estimates are discouraged. Because of the methodological differences and the variations in the reserves data, there does not appear to be a direct relationship between the results of the two analyses. The use of different data bases is another factor which renders the results incomparable.

It is essential that the question being asked be clearly understood in order to choose the appropriate methodology, and that any "replacement cost" results be interpreted in light of the methodology employed to obtain them. If an estimate is required of the costs incurred to obtain reserves additions in any particular year, then the short-term replacement cost estimates are pertinent. If, on the other hand, an estimate is required of the costs incurred to find and develop reserves from a particular discovery year, then the long-term replacement cost estimates would be relevant.

Short-term replacement costs were estimated for Alberta and Saskatchewan. The estimates for Alberta and Saskatchewan

respectively, for 1988, are $8.94 and $4.70 per BOE, $9.16 and $4.42 per barrel for crude oil, and $0.72 and $0.47 per Mcf (or $8.54 and $5.59 per BOE) of marketable natural gas. The short-term replacement cost estimates are lower for Saskatchewan than for Alberta, but caution is advised when comparing results from different jurisdictions as numerous factors can contribute to the results being incomparable and, perhaps, misleading.

Finding costs and long-term replacement costs were estimated for Alberta. The 1988 three-year moving average estimates of finding costs are $6.85 per BOE, $8.17 per barrel of crude oil, and $0.47 per Mcf (or $5.55 per BOE) of marketable natural gas. The 1988 three-year moving average estimates of long-term replacement costs are $12.69 per BOE, $17.28 per barrel of crude oil, and $0.70 per Mcf (or $8.24 per BOE) of marketable natural gas. Both the finding costs and the long-term replacement costs indicate downward trends since the early 1980s.

As discussed in Chapter 3, numerous methodological and data limitations are encountered when replacement costs are analysed on an aggregate level. Since accurate estimates of replacement costs would be useful for assessing the profitability of petroleum industry activity, it seems worthwhile to attempt to resolve the present problems. The methodological limitations can be handled by changing the assumptions used in the analysis to obtain new cost estimates based on the different assumptions. The data problems can be addressed in two ways: changes can be made to the way in which the aggregate reserves data are presented, or the analyses can be performed using disaggregate data.

If more accurate replacement cost estimates are to be obtained from aggregate analyses, the present problems with the aggregate reserves data must be resolved. First, it must be possible to isolate the portion of reserves additions that has occurred due to expenditures, rather than due to factors such as changes in economic conditions. This would require that the published aggregate reserves data be disaggregated to a greater extent than at present, using standardized definitions of terms such as "extensions" and "revisions." Second, if annual cost estimates are to be calculated, the annual reserves estimates must reflect the additions from each calendar year. (It should be noted that it is not the intention here to criticize the organizations that compile the aggregate data: often, those organizations can only compile the disaggregate data that is provided to them,

and it is faulty disaggregate data that adds up to problematic aggregate data.)

Another option for obtaining more accurate estimates of replacement costs is to conduct the analyses using disaggregate reserves data. It should be possible to isolate the reserves data required for the analyses from the perspective of an individual company. Thus, estimates by individual companies of their replacement costs have the potential to be more accurate than those for the entire industry.

In conclusion, the applicability of the results is influenced by the quality of the data employed in the analysis. The results presented in this study are the best that can be obtained using the methodologies and assumptions outlined in previous chapters with the available data. However, as numerous shortcomings of the data have been identified, caution is advised when using the replacement cost estimates.

APPENDIX A

BACKGROUND DATA AND METHODOLOGY

TABLE A.1

ALBERTA
NET CASH EXPLORATION EXPENDITURES
1970-1988
(millions of current dollars)

Year	Geological and Geophysical	Drilling	Land Purchase and Rentals	Total Exploration
1970	80.3	83.8	116.6	280.7
1971	65.5	80.8	125.9	272.2
1972	71.2	102.1	124.4	297.7
1973	70.7	131.4	144.3	346.4
1974	112.4	146.5	157.3	416.2
1975	99.0	149.1	207.9	456.0
1976	145.5	256.5	255.5	657.5
1977	223.4	394.7	679.9	1,298.0
1978	350.3	644.5	740.5	1,735.3
1979	349.7	1,027.5	1,144.7	2,521.9
1980	452.3	1,621.6	1,176.5	3,250.4
1981	352.2	1,543.7	721.3	2,617.2
1982	325.1	1,076.3	465.6	1,867.0
1983	372.7	1,017.4	565.1	1,955.2
1984	472.3	1,130.3	790.2	2,392.8
1985	480.5	1,368.3	1,021.1	2,869.9
1986	448.9	1,021.3	447.3	1,917.5
1987	420.0	1,010.8	841.1	2,271.9
1988	520.9	1,089.4	676.5	2,286.8

SOURCE: Canadian Petroleum Association, *CPA Statistical Handbook*, as updated to 1989 (Calgary, Alberta: Canadian Petroleum Association, 1989), Section IV, Tables 3A-3C.

TABLE A.2

ALBERTA
NET CASH DEVELOPMENT EXPENDITURES
1970-1988
(millions of current dollars)

Year	Drilling	Field Equipment	Secondary Recovery and Pressure Maintenance	Natural Gas Plants	Other	Total Development
1970	72.0	71.2	11.3	162.3	10.9	327.7
1971	55.5	75.5	19.5	214.0	11.6	376.1
1972	69.1	107.1	33.6	109.7	13.5	333.0
1973	101.7	127.4	37.3	65.3	19.0	350.7
1974	136.4	152.8	23.6	126.1	16.5	455.4
1975	212.3	181.0	19.9	123.8	25.0	562.0
1976	277.2	368.2	21.1	155.0	24.1	845.6
1977	351.2	298.1	29.0	143.8	39.1	861.2
1978	477.4	385.1	51.7	165.9	49.1	1,129.2
1979	679.2	476.3	78.2	204.7	99.9	1,538.3
1980	1,063.3	684.1	135.7	241.1	216.5	2,340.7
1981	1,083.2	782.7	142.9	310.9	98.6	2,418.3
1982	942.5	839.6	132.4	493.7	0.0	2,408.2
1983	906.3	653.8	59.3	179.7	2.3	1,801.4
1984	996.9	681.4	192.9	180.5	84.3	2,136.0
1985	1,296.1	902.5	331.0	263.3	87.0	2,879.9
1986	983.1	853.0	229.4	181.0	0.0	2,246.5
1987	883.1	768.4	223.3	162.3	0.0	2,037.1
1988	1,164.9	1,005.2	351.2	207.8	0.0	2,729.1

SOURCE: Canadian Petroleum Association, *CPA Statistical Handbook*, as updated to 1989 (Calgary, Alberta: Canadian Petroleum Association, 1989), Section IV, Tables 3A-3C.

TABLE A.3

SASKATCHEWAN
NET CASH EXPLORATION EXPENDITURES
1970-1988
(millions of current dollars)

Year	Geological and Geophysical	Drilling	Land Purchase and Rentals	Total Exploration
1970	2.9	5.8	12.3	21.0
1971	2.5	5.0	11.7	19.2
1972	3.2	5.1	12.8	21.1
1973	2.5	6.1	14.1	22.7
1974	1.0	5.8	14.0	20.8
1975	2.9	6.9	10.4	20.2
1976	3.5	9.7	20.3	33.5
1977	5.7	18.0	25.8	49.5
1978	12.6	20.2	52.7	85.5
1979	23.2	40.4	65.1	128.7
1980	31.0	60.6	90.7	182.3
1981	25.4	42.3	44.9	112.6
1982	22.3	34.6	42.7	99.6
1983	40.6	67.3	117.2	225.1
1984	41.9	100.4	132.5	274.8
1985	71.8	130.7	155.9	358.4
1986	34.9	53.3	26.8	115.0
1987	36.8	50.5	67.9	155.2
1988	38.1	86.1	46.6	170.8

SOURCE: Canadian Petroleum Association, *CPA Statistical Handbook*, as updated to 1989 (Calgary, Alberta: Canadian Petroleum Association, 1989), Section IV, Tables 4A-4C.

TABLE A.4

SASKATCHEWAN
NET CASH DEVELOPMENT EXPENDITURES
1970-1988
(millions of current dollars)

Year	Drilling	Field Equipment	Secondary Recovery and Pressure Maintenance	Natural Gas Plants	Other	Total Development
1970	9.5	14.5	3.6	0.6	0.6	28.8
1971	7.8	15.8	3.7	1.8	0.5	29.6
1972	9.0	8.7	2.6	0.2	0.4	20.9
1973	11.5	9.6	2.4	0.6	0.9	25.0
1974	6.9	11.5	1.6	0.5	3.0	23.5
1975	19.2	8.2	1.4	1.0	1.0	30.8
1976	10.0	9.1	0.9	0.2	0.8	21.0
1977	21.2	13.4	2.4	2.3	1.0	40.3
1978	48.0	22.4	4.0	2.4	2.3	79.1
1979	82.8	39.9	11.7	1.8	4.1	140.3
1980	97.1	64.3	25.5	0.1	8.2	195.2
1981	60.3	66.4	9.5	0.6	1.6	138.4
1982	72.0	55.7	18.9	2.3	0.0	148.9
1983	143.9	87.4	18.8	2.1	0.2	252.4
1984	241.7	129.6	39.1	6.9	7.2	424.5
1985	323.5	165.4	66.3	15.9	0.0	578.9
1986	142.4	76.8	28.1	8.6	0.0	255.9
1987	113.6	82.7	22.2	4.4	0.0	222.9
1988	190.9	138.2	20.9	24.7	0.0	374.7

SOURCE: Canadian Petroleum Association, *CPA Statistical Handbook*, as updated to 1989 (Calgary, Alberta: Canadian Petroleum Association, 1989), Section IV, Tables 4A-4C.

TABLE A.5

TOTAL EXPLORATION AND DEVELOPMENT EXPENDITURES
1970-1988
(millions of current dollars)

Year	Alberta	Saskatchewan
1970	608.4	49.8
1971	648.3	48.8
1972	630.7	42.0
1973	697.1	47.7
1974	871.6	44.3
1975	1,018.0	51.0
1976	1,503.1	54.5
1977	2,159.2	89.8
1978	2,864.5	164.6
1979	4,060.2	269.0
1980	5,591.1	377.5
1981	5,035.5	251.0
1982	4,275.2	248.5
1983	3,756.6	477.5
1984	4,528.8	699.3
1985	5,749.8	937.3
1986	4,164.0	370.9
1987	4,309.0	378.1
1988	5,015.9	545.5

SOURCES: Tables A.1 to A.4.

TABLE A.6

COST ESCALATION INDICES BY
EXPENDITURE TYPE
1970-1988
(1988 = 100)

Year	Geological and Geophysical Costs	Exploration and Development Drilling	EOR and Field Equipment	Gas Plant Construction Costs	Total Construction Costs	GDP Deflator
1970	25.9	19.2	21.5	12.0	19.1	30.4
1971	27.7	19.8	23.1	13.5	20.7	31.3
1972	29.2	22.1	25.7	15.0	22.7	32.9
1973	31.3	25.4	30.6	16.7	26.0	35.9
1974	34.6	30.2	38.8	19.0	31.2	41.1
1975	42.9	35.5	45.9	22.4	36.9	45.1
1976	48.0	40.6	51.7	31.3	43.4	49.0
1977	53.0	44.5	58.0	40.1	48.0	52.1
1978	61.6	52.1	62.5	48.9	54.6	55.2
1979	66.7	62.7	70.0	54.7	63.3	60.7
1980	72.9	77.8	76.9	60.3	75.0	67.2
1981	78.0	86.0	86.6	68.1	84.0	74.4
1982	83.2	89.7	93.9	74.3	88.6	80.9
1983	78.3	88.8	95.9	78.7	87.4	84.9
1984	79.1	91.5	95.9	84.2	89.7	87.6
1985	86.9	98.0	92.0	88.4	95.0	89.9
1986	92.0	92.0	92.0	92.0	92.0	92.0
1987[a]	96.1	96.1	96.1	96.1	96.1	96.1
1988[a]	100.0	100.0	100.0	100.0	100.0	100.0

SOURCES: (1) Canadian Petroleum Association, "Alberta Oil and Gas Industry Cost Escalation Study Update 1970-1986" (Calgary, Alberta: Canadian Petroleum Association, December 1987), mimeographed; (2) Canadian Petroleum Association, Personal Communication; (3) Bank of Canada, *Bank of Canada Review* (Ottawa, Ontario: Bank of Canada, October 1989); and (4) Canadian Energy Research Institute.

[a]CPA cost escalation rates are available only for the time period 1970 to 1986. The GDP deflator is used as the cost escalation rate for all expenditure components for 1987 and 1988.

TABLE A.7

ALBERTA
CONSTANT DOLLAR NET CASH EXPLORATION EXPENDITURES
1970-1988
(millions of $1988)

Year	Geological and Geophysical	Drilling	Land Purchase and Rentals	Total Exploration
1970	310.6	435.8	606.3	1,352.7
1971	236.5	408.4	636.4	1,281.3
1972	244.1	462.3	563.3	1,269.8
1973	226.0	517.4	568.2	1,311.6
1974	324.9	485.4	521.2	1,331.5
1975	230.9	419.8	585.4	1,236.0
1976	302.9	632.1	629.7	1,564.7
1977	421.5	886.3	1,526.7	2,834.5
1978	569.1	1,237.5	1,421.9	3,228.5
1979	524.2	1,639.8	1,826.8	3,990.8
1980	620.7	2,083.2	1,511.4	4,215.2
1981	451.4	1,794.3	838.4	3,084.1
1982	390.8	1,199.7	519.0	2,109.6
1983	476.0	1,145.8	636.4	2,258.2
1984	596.9	1,235.8	864.0	2,696.7
1985	553.2	1,396.3	1,042.0	2,991.5
1986	487.9	1,110.0	486.1	2,083.9
1987	437.2	1,052.2	875.6	2,365.0
1988	520.9	1,089.4	676.5	2,286.8

SOURCES: Tables A.1 and A.6.

TABLE A.8

ALBERTA
CONSTANT DOLLAR NET CASH DEVELOPMENT EXPENDITURES
1970-1988
(millions of $1988)

Year	Drilling	Field Equipment	Secondary Recovery and Pressure Maintenance	Natural Gas Plants	Other	Total Development
1970	374.4	330.7	52.5	1,356.8	35.9	2,150.3
1971	280.5	326.9	84.4	1,582.2	37.0	2,311.1
1972	312.9	417.2	130.9	731.4	41.0	1,633.5
1973	400.5	415.8	121.7	392.1	52.9	1,383.0
1974	452.0	393.5	60.8	662.1	40.2	1,608.5
1975	597.7	394.2	43.3	553.7	55.4	1,644.4
1976	683.1	712.0	40.8	495.5	49.1	1,980.6
1977	788.6	514.2	50.0	358.4	75.1	1,786.4
1978	916.7	616.4	82.8	339.5	88.9	2,044.3
1979	1,083.9	680.2	111.7	373.9	164.5	2,414.2
1980	1,366.0	889.3	176.4	400.0	322.3	3,154.1
1981	1,259.1	904.0	165.0	456.6	132.5	2,917.2
1982	1,050.6	893.7	140.9	664.9	0.0	2,750.1
1983	1,020.7	681.9	61.8	228.4	2.7	1,995.6
1984	1,090.0	710.7	201.2	214.4	96.3	2,312.5
1985	1,322.6	980.8	359.7	297.8	96.8	3,057.8
1986	1,068.4	927.0	249.3	196.7	0.0	2,441.5
1987	919.3	799.9	232.5	169.0	0.0	2,120.6
1988	1,164.9	1,005.2	351.2	207.8	0.0	2,729.1

SOURCES: Tables A.2 and A.6.

TABLE A.9

SASKATCHEWAN
CONSTANT DOLLAR NET CASH
EXPLORATION EXPENDITURES
1970-1988
(millions of $1988)

Year	Geological and Geophysical	Drilling	Land Purchase and Rentals	Total Exploration
1970	11.2	30.2	64.0	105.3
1971	9.0	25.3	59.1	93.4
1972	11.0	23.1	58.0	92.0
1973	8.0	24.0	55.5	87.5
1974	2.9	19.2	46.4	68.5
1975	6.8	19.4	29.3	55.5
1976	7.3	23.9	50.0	81.2
1977	10.8	40.4	57.9	109.1
1978	20.5	38.8	101.2	160.4
1979	34.8	64.5	103.9	203.1
1980	42.5	77.8	116.5	236.9
1981	32.6	49.2	52.2	133.9
1982	26.8	38.6	47.6	113.0
1983	51.8	75.8	132.0	259.6
1984	53.0	109.8	144.9	307.6
1985	82.7	133.4	159.1	375.1
1986	37.9	57.9	29.1	125.0
1987	38.3	52.6	70.7	161.6
1988	38.1	86.1	46.6	170.8

SOURCES: Tables A.3 and A.6.

TABLE A.10

SASKATCHEWAN
CONSTANT DOLLAR NET CASH DEVELOPMENT EXPENDITURES
1970-1988
(millions of $1988)

Year	Drilling	Field Equipment	Secondary Recovery and Pressure Maintenance	Natural Gas Plants	Other	Total Development
1970	49.4	67.3	16.7	5.0	2.0	140.5
1971	39.4	68.4	16.0	13.3	1.6	138.8
1972	40.8	33.9	10.1	1.3	1.2	87.3
1973	45.3	31.3	7.8	3.6	2.5	90.6
1974	22.9	29.6	4.1	2.6	7.3	66.5
1975	54.1	17.9	3.0	4.5	2.2	81.7
1976	24.6	17.6	1.7	0.6	1.6	46.3
1977	47.6	23.1	4.1	5.7	1.9	82.5
1978	92.2	35.9	6.4	4.9	4.2	143.5
1979	132.1	57.0	16.7	3.3	6.8	215.9
1980	124.7	83.6	33.2	0.2	12.2	253.9
1981	70.1	76.7	11.0	0.9	2.1	160.8
1982	80.3	59.3	20.1	3.1	0.0	162.8
1983	162.1	91.2	19.6	2.7	0.2	275.7
1984	264.3	135.2	40.8	8.2	8.2	456.6
1985	330.1	179.8	72.1	18.0	8.7	608.6
1986	154.8	83.5	30.5	9.3	0.0	278.1
1987	118.3	86.1	23.1	4.6	0.0	232.0
1988	190.9	138.2	20.9	24.7	0.0	374.7

SOURCES: Tables A.4 and A.6.

TABLE A.11

TOTAL CONSTANT DOLLAR EXPLORATION AND DEVELOPMENT EXPENDITURES
1970-1988
(millions of $1988)

Year	Alberta	Saskatchewan
1970	3,502.9	245.8
1971	3,592.4	232.2
1972	2,903.2	179.4
1973	2,694.6	178.1
1974	2,940.0	135.0
1975	2,880.4	137.1
1976	3,545.3	127.5
1977	4,620.9	191.6
1978	5,272.8	303.9
1979	6,405.0	419.0
1980	7,369.3	490.8
1981	6,001.3	294.7
1982	4,859.7	275.7
1983	4,253.8	535.4
1984	5,009.2	764.2
1985	6,049.3	983.7
1986	4,525.5	403.1
1987	4,485.7	393.6
1988	5,015.9	545.5

SOURCES: Tables A.7 to A.10.

TABLE A.12

ALBERTA
ANNUAL RESERVES ADDITIONS FOR CRUDE OIL AND MARKETABLE NATURAL GAS

Year	Crude Oil		Marketable Natural Gas	
	Unadjusted Reserves Additions[a] (MMb)	Adjusted Reserves Additions[b] (MMb)	Unadjusted Reserves Additions[c] (Bcf)	Adjusted Reserves Additions[d] (Bcf)
1979	215.8		4,336.6	
1980	142.9		3,252.5	
1981	205.2		4,118.4	
1982	43.4		4,178.2	
1983	403.4		1,372.8	
1984	259.3		1,425.6	
1985	402.8	408.4	1,499.5	2,238.7
1986	246.1	439.3	767.4	2,196.5
1987	207.7	278.2	0.0	1,302.4
1988	231.0	329.8	2,273.9	2,207.0

SOURCES: (1) Alberta Energy Resources Conservation Board, *Alberta's Reserves of Crude Oil, Oil Sands, Gas, Natural Gas Liquids, and Sulphur*, 1988 edition (Calgary, Alberta: Energy Resources Conservation Board, 1988); (2) Energy Resources Conservation Board, Personal Communication; and (3) Canadian Energy Research Institute.

[a]Unadjusted crude oil reserves additions = New Discoveries + Development and Re-evaluation + Enhanced Recovery. The provincial annual estimates of reserves additions due to new discoveries, development and re-evaluation and enhanced recovery are used in the calculations.

[b]Adjusted crude oil reserves additions = New Discoveries + Development + Enhanced Recovery. In 1985, the ERCB began identifying the development component of the reserves additions generated through development and re-evaluation. The adjusted estimates of reserves additions thus exclude reserves additions which occur due to re-evaluation.

[c]Unadjusted marketable natural gas reserves additions = New Discoveries + Development and Re-evaluation. The provincial annual estimates of reserves additions from new discoveries and development and re-evaluation are used in the calculations.

[d]Adjusted marketable natural gas reserves additions are calculated by excluding the negative revisions that occurred as the result of a review of small gas pools.

TABLE A.13

SASKATCHEWAN
ANNUAL RESERVES ADDITIONS FOR
CRUDE OIL AND MARKETABLE NATURAL GAS

Year	Crude Oil		Marketable Natural Gas	
	Unadjusted Reserves Additions[a] (MMb)	Adjusted Reserves Additions[b] (MMb)	Unadjusted Reserves Additions[c] (Bcf)	Adjusted Reserves Additions[d] (Bcf)
1979	37.4		65.2	
1980	51.6		73.2	
1981	24.9		100.5	
1982	36.4		139.3	
1983	84.3		219.4	
1984	103.5		381.9	
1985	99.0	136.9	232.8	232.8
1986	72.2	65.1	221.8	221.8
1987	87.1	66.9	143.7	143.7
1988	122.1	82.5	306.8	306.8

SOURCES: (1) Saskatchewan Energy and Mines, *Reservoir Annual*, 1979 to 1988 editions. (Regina, Saskatchewan: Saskatchewan Energy and Mines, 1979-1988); (2) Saskatchewan Energy and Mines, Personal Communication; and (3) Canadian Energy Research Institute.

[a]Unadjusted crude oil reserves additions = Drilling + Revisions. The provincial annual estimates of reserves additions from drilling and revisions are used in the calculations.

[b]Adjusted crude oil reserves additions = Drilling + Adjusted Revisions. The estimate of adjusted reserves additions is calculated by allocating the total revisions from the 1979-1988 period evenly to the various years in the time period; this removes the effect of volatile revisions estimates on the estimates of reserves additions for individual years.

[c]Unadjusted marketable natural gas reserves additions are calculated from the published annual estimates of remaining established reserves and production, after making the adjustments explained in Chapter 4 that are required to obtain estimates of marketable natural gas.

[d]As explained in Chapter 4, it is not possible to isolate the portion of revisions that is due to expenditures. Therefore, the unadjusted estimates of reserves additions are assumed to be the best obtainable estimates.

TABLE A.14

ALBERTA CRUDE OIL: DETERMINATION OF APPRECIATION RATES[a]

Year of Discovery	Number of Years After Discovery								
	0	1	2	3	4	5	6	7	8
1970	41,281	47,731	49,217	41,107	41,175	41,157	40,129	39,805	43,390
1971	19,271	26,827	31,512	41,904	41,200	40,964	38,701	40,099	36,921
1972	8,372	11,622	17,303	15,920	15,907	31,525	34,303	32,075	32,075
1973	11,227	11,327	32,377	48,953	39,854	36,732	39,344	36,707	37,154
1974	4,783	7,281	10,402	14,468	16,186	18,564	20,578	23,907	25,052
1975	1,982	7,023	6,457	7,287	8,074	7,671	7,740	9,798	9,496
1976	1,378	4,732	17,413	106,163	107,585	33,063	38,777	41,188	49,507
1977	62,892	175,996	181,364	199,079	48,248	58,626	71,960	83,779	90,242
1978	4,669	44,536	54,239	178,658	186,128	200,526	248,378	294,575	310,453
1979	30,968	51,275	97,019	94,521	115,986	157,363	175,147	172,062	190,558
1980	36,839	15,909	21,887	24,127	82,891	89,744	98,857	123,557	110,228
1981	34,756	53,031	62,804	50,847	56,473	58,223	68,694	63,805	
1982	48,853	63,817	164,713	165,896	145,419	159,093	93,942		
1983	26,613	152,486	147,067	140,630	150,459	136,923			
1984	100,299	85,799	119,145	136,766	125,067				
1985	175,562	123,683	191,257	190,432					
1986	86,678	100,461	125,992						
1987	124,451	144,173							
1988	69,176								
Annual Appreciation Factor[b]	1.0	1.374	1.352	1.210	0.932	1.014	1.046	1.089	1.042
Compounded Appreciation Rate[c]	1.0	1.374	1.858	2.248	2.096	2.125	2.223	2.422	2.523

(Continued on Next Page)

TABLE A.14 (Continued)

Year of Discovery	Number of Years After Discovery									
	9	10	11	12	13	14	15	16	17	18
1970	47,720	46,990	47,103	50,281	51,250	28,243	22,693	25,361	27,463	27,286
1971	43,208	54,390	58,550	51,439	53,119	59,557	61,017	66,171	68,550	
1972	33,561	34,335	35,039	20,352	20,169	22,913	22,560	30,458		
1973	36,707	39,658	119,366	132,184	137,578	141,876	192,094			
1974	24,102	24,492	25,367	26,280	32,541	51,552				
1975	7,627	10,006	10,276	24,725	26,695					
1976	50,124	50,722	78,442	40,860						
1977	90,342	118,107	165,909							
1978	318,426	321,824								
1979	205,863									
1980										
1981										
1982										
1983										
1984										
1985										
1986										
1987										
1988										
Annual Appreciation Factor[b]	1.040	1.075	1.426	0.925	1.053	1.032	1.181	1.148	1.049	0.994
Compounded Appreciation Rate[c]	2.624	2.820	4.021	3.720	3.916	4.042	4.774	5.481	5.749	5.712

SOURCES: (1) Canadian Energy Research Institute; (2) Canadian Petroleum Association, *CPA Statistical Handbook*, 1971 to 1989 editions (Calgary, Alberta: Canadian Petroleum Association, 1971-1989), Reserves Section; (3) Canadian Petroleum Association, Personal Communication; (4) Alberta Energy Resources Conservation Board, Personal Communication; and (5) *Oilweek*, 1984-1989 (various issues).

[a]Appreciation rates are calculated from estimates of crude oil reserves, measured in thousands of barrels (Mb). Reserves estimates made in 1970 to 1977 are of ultimate recoverable crude oil reserves; estimates made in 1978 are of initial established in-place crude oil reserves; and estimates made in 1979 to 1988 are of initial established crude oil reserves.

[b]Calculated as the sum of one column divided by the sum of the previous column less the last entry (so both column totals include the same years).

[c]Calculated by compounding (multiplying) the annual appreciation factors to yield the total appreciation rate.

TABLE A.15

ALBERTA CRUDE OIL: CALCULATION OF SMOOTHED ANNUAL APPRECIATION FACTORS

Years After Discovery	Smoothed Annual Appreciation Factor[b]	Smoothed Compounded Appreciation Rate[a]	
0	1.0	1.0	= 1.0
1	1.7	1.0 x 1.7	= 1.7
2	1.235	1.0 x 1.7 x 1.235	= 2.1
3	1.095	1.0 x 1.7 x 1.235 x 1.095	= 2.3
4	1.087	1.0 x 1.7 x 1.235 x 1.095 x 1.087	= 2.5
5	1.08	1.0 x 1.7 x 1.235 x 1.095 x 1.087 x 1.08	= 2.7
>5	1.0	1.0 x 1.7 x 1.235 x 1.095 x 1.087 x 1.08 x 1.0	= 2.7

SOURCES: (1) Table A.14; (2) Michele McLachlan, *Oil and Gas Finding Costs in Alberta: 1970-1987* (Calgary, Alberta: Canadian Energy Research Institute, May 1989); and (3) Canadian Energy Research Institute.

[a]These rates were obtained by smoothing the compounded appreciation rates to obtain the five-year development profile assumed to be appropriate for crude oil reserves. As shown in Table A.14, there is no clear point at which the crude oil reserves appear to be fully appreciated, with appreciation continuing well beyond the five-year appreciation profile that was assumed to be appropriate in the previous finding cost studies. The appreciation rate used to estimate long-term replacement costs should reflect all appreciation; however, as discussed in Chapter 5, the problems with the reserves booking procedures sometimes result in discoveries initially being underestimated, and appreciation of the reserves then being overestimated, thus resulting in an appreciation rate calculated from the aggregate data that would overestimate the actual appreciation rate. Due to the uncertainty about the accuracy of the appreciation rate calculated from aggregate data, the appreciation rates employed in the previous studies have been used here to provide continuity and comparability between studies.

[b]These annual appreciation factors were calculated from the smoothed compounded appreciation rates. For example, compounded appreciation rates of 1.7 and 2.1 for one and two years, respectively, after discovery imply an annual appreciation factor in the second year after discovery of 1.235 (2.1/1.7 = 1.235).

TABLE A.16

ALBERTA CRUDE OIL: CALCULATION OF REMAINING COMPOUNDED APPRECIATION RATES

Years After Discovery	Smoothed Annual Appreciation Factor	Remaining Compounded Appreciation Rate[a]
0	1.0	1.7 x 1.235 x 1.095 x 1.087 x 1.08 x 1.0 = 2.70
1	1.7	1.235 x 1.095 x 1.087 x 1.08 x 1.0 = 1.59
2	1.235	1.095 x 1.087 x 1.08 x 1.0 = 1.29
3	1.095	1.087 x 1.08 x 1.0 = 1.17
4	1.087	1.08 x 1.0 = 1.08
5	1.08	1.0 = 1.00
>5	1.00	1.0 = 1.00

SOURCES: (1) Table A.15; and (2) Michele McLachlan, *Oil and Gas Finding Costs in Alberta: 1970-1987* (Calgary, Alberta: Canadian Energy Research Institute, May 1989).

[a]Compounding the annual appreciation factors which are not yet reflected in the reserves estimates provides the appreciation rates which are needed to calculate estimates of fully appreciated reserves for the various discovery years. These remaining compounded appreciation rates are used in Table A.20.

TABLE A.17

ALBERTA MARKETABLE NATURAL GAS: DETERMINATION OF APPRECIATION RATES[a]

Year of Discovery	Number of Years After Discovery								
	0	1	2	3	4	5	6	7	8
1970	332,084	601,915	584,464	721,147	731,100	944,862	819,999	923,915	967,155
1971	651,995	1,194,710	1,117,208	1,017,980	947,535	987,000	1,907,150	1,268,432	1,444,150
1972	568,884	1,005,083	1,205,427	1,175,610	1,525,184	1,456,720	1,375,686	1,484,208	2,052,301
1973	1,350,713	284,360	774,622	877,813	883,025	1,143,754	1,007,354	1,110,736	1,171,914
1974	240,276	658,762	1,277,216	1,527,040	1,685,306	3,050,502	3,273,530	3,399,862	3,560,938
1975	442,775	604,062	614,725	1,251,853	1,654,893	1,806,922	1,837,440	2,002,880	1,860,496
1976	617,612	1,112,870	1,879,152	2,538,272	2,245,584	2,259,594	2,296,800	2,368,326	3,649,818
1977	263,127	1,161,811	1,598,890	1,548,694	1,983,414	2,011,715	2,130,550	3,742,992	3,654,288
1978	1,001,264	1,224,995	1,865,002	1,837,053	1,889,958	1,688,755	2,962,608	3,151,738	3,127,274
1979	535,498	1,558,586	1,877,779	2,772,845	2,970,422	3,149,942	3,105,520	3,109,181	2,996,541
1980	383,187	711,568	802,278	1,014,218	3,219,744	3,271,347	2,368,538	2,746,269	3,365,507
1981	544,333	684,253	891,862	2,369,629	2,311,866	2,338,477	2,193,946	2,336,435	
1982	125,171	1,504,765	1,336,192	1,338,867	1,432,077	1,320,774	1,296,416		
1983	194,374	947,408	1,113,306	1,223,341	1,073,565	1,161,213			
1984	389,073	990,880	1,158,045	1,141,290	1,209,014				
1985	470,385	914,707	942,234	1,113,834					
1986	374,881	1,129,322	1,243,581						
1987	411,677	884,752							
1988	567,428								
Annual Appreciation Factor[b]	1.0	1.930	1.245	1.233	1.152	1.083	1.012	1.131	1.100
Compounded Appreciation Rate[c]	1.0	1.930	2.403	2.963	3.414	3.698	3.744	4.233	4.658

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TABLE A.17 (Continued)

Year of Discovery	Number of Years After Discovery									
	9	10	11	12	13	14	15	16	17	18
1970	690,307	997,498	959,059	1,041,005	798,160	1,023,158	1,141,853	1,108,342	1,094,157	1,256,394
1971	1,579,107	1,661,546	1,513,635	1,448,304	1,534,262	1,323,802	1,305,181	1,305,392	1,307,187	
1972	1,937,654	1,830,893	2,085,706	2,675,869	2,626,378	2,582,765	2,589,805	2,599,168		
1973	1,276,035	1,292,826	2,053,850	2,041,213	2,027,520	1,970,531	1,891,507			
1974	3,557,488	2,293,773	2,404,266	2,647,357	3,000,976	3,020,195				
1975	1,982,851	1,996,579	1,696,605	1,627,014	1,542,464					
1976	3,453,402	3,175,885	3,103,725	3,396,026						
1977	3,693,958	3,839,792	3,769,462							
1978	3,018,365	3,229,494								
1979	2,878,867									
1980										
1981										
1982										
1983										
1984										
1985										
1986										
1987										
1988										
Annual Appreciation Factor[b]	0.983	0.959	1.029	1.077	1.004	0.993	1.004	0.995	0.995	1.148
Compounded Appreciation Rate[c]	4.579	4.390	4.518	4.865	4.886	4.853	4.873	4.850	4.825	5.540

SOURCES: (1) Canadian Energy Research Institute; (2) Canadian Petroleum Association, *CPA Statistical Handbook*, as updated to 1989 (Calgary, Alberta: Canadian Petroleum Association, 1989), Reserves Section; (3) Canadian Petroleum Association, Personal Communication; (4) Alberta Energy Resources Conservation Board, Personal Communication: and (5) *Oilweek*, 1984-1989 (various issues).

[a]Appreciation rates are calculated from estimates of marketable natural gas reserves, measured in millions of cubic feet (MMcf). Reserves estimates made in 1970 to 1977 are of ultimate recoverable marketable natural gas reserves, and estimates made in 1978 to 1988 are of initial established marketable natural gas reserves.

[b]Calculated as the sum of one column divided by the sum of the previous column less the last entry (so both column totals include the same years).

[c]Calculated by compounding (multiplying) the annual appreciation factors to yield the total appreciation rate.

TABLE A.18

ALBERTA MARKETABLE NATURAL GAS: CALCULATION OF SMOOTHED ANNUAL APPRECIATION FACTORS

Years After Discovery	Smoothed Annual Appreciation Factor[b]	Smoothed Compounded Appreciation Rate[a]	
0	1.0	1.0	= 1.0
1	2.0	1.0 x 2.0	= 2.0
2	1.5	1.0 x 2.0 x 1.5	= 3.0
3	1.233	1.0 x 2.0 x 1.5 x 1.233	= 3.7
4	1.162	1.0 x 2.0 x 1.5 x 1.233 x 1.162	= 4.3
5	1.116	1.0 x 2.0 x 1.5 x 1.233 x 1.162 x 1.116	= 4.8
>5	1.0	1.0 x 2.0 x 1.5 x 1.233 x 1.162 x 1.116 x 1.0	= 4.8

SOURCES: (1) Table A.17; (2) Michele McLachlan, *Oil and Gas Finding Costs in Alberta: 1970-1987* (Calgary, Alberta: Canadian Energy Research Institute, May 1989); and (3) Canadian Energy Research Institute.

[a]These rates were obtained by smoothing the compounded appreciation rates (in Table A.17) to obtain a five-year development profile for marketable natural gas reserves. These smoothed compounded appreciation rates differ somewhat from the compounded appreciation rates in Table A.17. Since, first, reserves are assumed to appreciate over a five-year development profile and, second, the appreciation rate eventually stabilizes at approximately 4.8, it was decided to use an appreciation rate of 4.8 which is attained after the assumed five-year development profile.

[b]These annual appreciation factors were calculated from the smoothed compounded appreciation rates. For example, compounded appreciation rates of 2.0 and 3.0 for one and two years, respectively, after discovery imply an annual appreciation factor in the second year after discovery of 1.5 (3.0/2.0 = 1.5).

TABLE A.19

ALBERTA MARKETABLE NATURAL GAS: CALCULATION OF REMAINING COMPOUNDED APPRECIATION RATES

Years After Discovery	Annual Appreciation Factor	Remaining Compounded Appreciation Rate[a]
0	1.0	2.0 x 1.5 x 1.233 x 1.162 x 1.116 x 1.0 = 4.80
1	2.0	1.5 x 1.233 x 1.162 x 1.116 x 1.0 = 2.40
2	1.5	1.233 x 1.162 x 1.116 x 1.0 = 1.60
3	1.233	1.162 x 1.116 x 1.0 = 1.30
4	1.162	1.116 x 1.0 = 1.12
5	1.116	1.0 = 1.00
>5	1.0	1.0 = 1.00

SOURCES: (1) Table A.18; (2) Michele McLachlan, *Oil and Gas Finding Costs in Alberta: 1970-1987* (Calgary, Alberta: Canadian Energy Research Institute, May 1989); and (3) Canadian Energy Research Institute.

[a]Compounding the annual appreciation factors which are not yet reflected in the reserves estimates provides the appreciation rates which are needed to calculate estimates of fully appreciated reserves for the various discovery years. These remaining compounded appreciation rates are used in Table A.20.

TABLE A.20

RESERVES ESTIMATES FOR CRUDE OIL AND MARKETABLE NATURAL GAS IN ALBERTA BY YEAR OF DISCOVERY AT DECEMBER 31, 1988 (1970-1988)

Year	Reserves Estimates		Appreciation Rate[a]		Fully Appreciated Reserves[b]	
	Crude Oil (Mb)	Marketable Gas (MMcf)	Crude Oil	Marketable Gas	Crude Oil (Mb)	Marketable Gas (MMcf)
1970	27,286.4	1,260,487.6	1.00	1.00	27,286.4	1,260,487.6
1971	68,549.6	1,311,446.7	1.00	1.00	68,549.6	1,311,446.7
1972	30,458.1	2,607,637.4	1.00	1.00	30,458.1	2,607,637.4
1973	192,093.8	1,897,670.7	1.00	1.00	192,093.8	1,897,670.7
1974	51,552.3	3,030,036.6	1.00	1.00	51,552.3	3,030,036.6
1975	26,694.9	1,547,490.2	1.00	1.00	26,694.9	1,547,490.2
1976	40,860.4	3,407,091.6	1.00	1.00	40,860.4	3,407,091.6
1977	165,908.7	3,781,745.3	1.00	1.00	165,908.7	3,781,745.3
1978	321,824.0	3,240,017.8	1.00	1.00	321,824.0	3,240,017.8
1979	205,862.9	2,888,248.1	1.00	1.00	205,862.9	2,888,248.1
1980	110,228.2	3,376,473.8	1.00	1.00	110,228.2	3,376,473.8
1981	63,804.7	2,344,048.5	1.00	1.00	63,804.7	2,344,048.5
1982	93,941.9	1,300,640.4	1.00	1.00	93,941.9	1,300,640.4
1983	136,923.1	1,164,996.6	1.00	1.00	136,923.1	1,164,996.6
1984	125,067.1	1,212,954.0	1.08	1.12	135,072.4	1,353,996.2
1985	190,432.5	1,117,463.1	1.17	1.30	223,551.2	1,449,681.8
1986	125,992.2	1,247,633.0	1.29	1.60	161,989.9	1,996,212.9
1987	144,172.6	887,635.0	1.59	2.40	228,980.1	2,130,324.0
1988	69,176.4[c]	569,277.1[c]	2.70	4.80	186,776.4	2,732,529.9

SOURCES: (1) Canadian Energy Research Institute; (2) Canadian Petroleum Association, *CPA Statistical Handbook*, 1989 edition (Calgary, Alberta: Canadian Petroleum Association, 1989), Reserves Section; (3) Canadian Petroleum Association, Personal Communication; (4) Alberta Energy Resources Conservation Board, Personal Communication; (5) *Oilweek*, November 7, 14, 1988; and January 16, 1989; and (6) Tables A.16 and A.19.

[a]Reserves are assumed to be fully appreciated five years after discovery. Therefore, no further appreciation is expected in reserves discovered prior to 1984.

[b]Reserves multiplied by the appreciation rate.

[c]The published reserves estimates for the most recent discovery year reflect discoveries made in the period January to October. Therefore, the 1988 reserves estimates listed above include a multiplication factor of 1.18 to adjust for the percentage of exploratory metres drilled in Alberta in 1988 that occurred in November and December.

TABLE A.21

COMPARISON OF CRUDE OIL AND NATURAL GAS PRICES 1970-1988

Year	Crude Oil Price[a] ($/bbl)		Natural Gas Price[b] ($/Mcf)		Oil/Gas Price Ratio[c] (Mcf/bbl)	
	Alberta	Saskatchewan	Alberta	Saskatchewan	Alberta	Saskatchewan
1970	2.55	2.22	0.16	0.13	15.94	17.02
1971	2.83	2.45	0.16	0.13	17.69	18.74
1972	2.84	2.45	0.17	0.13	16.71	18.89
1973	3.48	3.05	0.19	0.14	18.32	22.35
1974	5.78	5.35	0.30	0.15	19.27	36.07
1975	7.26	6.85	0.62	0.17	11.71	40.10
1976	8.50	7.90	1.00	0.21	8.50	37.95
1977	10.21	9.39	1.29	0.31	7.91	30.26
1978	12.21	11.33	1.49	0.43	8.19	26.33
1979	13.18	12.29	1.69	0.42	7.80	29.57
1980	15.53	14.65	2.34	0.47	6.64	31.45
1981	18.79	17.60	2.47	0.47	7.61	37.41
1982	25.68	27.88	2.67	0.54	9.62	51.47
1983	31.82	29.70	2.84	1.08	11.20	27.38
1984	33.38	31.97	2.94	1.44	11.35	22.15
1985	34.06	32.50	2.80	1.64	12.17	19.85
1986	18.74	15.94	2.20	1.53	8.52	10.44
1987	22.58	19.89	1.70	1.84	13.28	10.84
1988	16.75	13.42	1.53	1.44	10.94	9.35
Average	15.06	14.04	1.50	0.67	11.76[d]	26.19[d]

SOURCES: (1) Canadian Petroleum Association, *CPA Statistical Handbook*, 1989 edition (Calgary, Alberta: Canadian Petroleum Association, 1989), Section VI, Table 2; and (2) Canadian Energy Research Institute.

[a]Average wellhead price, converted from dollars per cubic metre.
[b]Average wellhead/plant gate price, converted from dollars per thousand cubic metres.
[c]Crude oil price divided by natural gas price.
[d]This is the average wellhead price equivalence, calculated as the average of the price ratios, which is used to convert natural gas reserves to crude oil equivalent.

TABLE A.22

CRUDE OIL INTENT
1970-1988

Year	Alberta		Saskatchewan	
	Exploratory Oil Intent[a]	Development Oil Intent[b]	Exploratory Oil Intent[a]	Development Oil Intent[b]
1970	0.275	0.447	0.787	0.940
1971	0.374	0.465	0.554	0.818
1972	0.221	0.565	0.533	0.909
1973	0.214	0.478	0.630	0.949
1974	0.198	0.461	0.364	0.519
1975	0.179	0.389	0.473	0.663
1976	0.141	0.255	0.848	0.963
1977	0.154	0.306	0.810	0.884
1978	0.197	0.370	0.962	0.960
1979	0.262	0.448	0.935	0.975
1980	0.253	0.442	0.959	0.972
1981	0.297	0.444	0.944	0.982
1982	0.447	0.551	0.969	0.999
1983	0.558	0.749	0.822	0.946
1984	0.597	0.774	0.803	0.911
1985	0.652	0.702	0.818	0.922
1986	0.604	0.740	0.719	0.859
1987	0.590	0.772	0.589	0.733
1988	0.490	0.707	0.530	0.760

SOURCE: Canadian Petroleum Association, *CPA Statistical Handbook*, as updated to 1989 (Calgary, Alberta: Canadian Petroleum Association, 1989), Drilling Section.

[a]Calculated as successful crude oil exploratory metres drilled divided by total successful exploratory metres drilled.

[b]Calculated as successful crude oil development metres drilled divided by total successful development metres drilled.

TABLE A.23

LONG-TERM BOND YIELDS[a]
1970-1988
(percent)

Year	Yield
1970	9.18
1971	8.35
1972	8.30
1973	8.47
1974	10.17
1975	10.76
1976	10.48
1977	9.71
1978	10.10
1979	10.92
1980	13.28
1981	16.32
1982	15.86
1983	12.74
1984	13.50
1985	11.74
1986	10.27
1987	10.71
1988	10.93

SOURCE: Bank of Canada, *Bank of Canada Review*, 1971 to 1989 editions.

[a]Annual average of McLeod, Young, Weir 10 Industrials bond yields (for 1970-1977); McLeod, Young, Weir weighted long-term corporate bond yields (for 1978-1987); and Scotia McLeod weighted long-term corporate bond yields (for 1988).

APPENDIX B

SHORT-TERM REPLACEMENT COST RESULTS

TABLE B.1

ALBERTA
SHORT-TERM REPLACEMENT COST ESTIMATES
1979-1988
(1988 constant dollars)

Year	Crude Oil Equivalent		Crude Oil		Marketable Natural Gas			
	Base Case ($/BOE)	Unadjusted Case ($/BOE)	Base Case ($/bbl)	Unadjusted Case ($/bbl)	Base Case ($/Mcf)	Unadjusted Case ($/Mcf)	Base Case ($/BOE)	Unadjusted Case ($/BOE)
1979		9.54		7.97		0.89		10.46
1980		15.59		15.47		1.33		15.65
1981		11.82		11.27		1.03		12.14
1982		13.74		53.44		0.75		8.87
1983		8.65		6.25		1.44		16.96
1984		11.97		11.61		1.08		12.74
1985	9.21	10.39	9.14	9.27	0.79	1.18	9.35	13.96
1986	8.07	16.22	7.83	13.97	0.73	2.09	8.63	24.72
1987	12.47	23.34	12.07	16.17	1.14	∞[a]	13.49	∞[a]
1988	8.94	10.90	9.16	13.09	0.72	0.70	8.54	8.29

SOURCE: Canadian Energy Research Institute.

[a]Replacement cost is infinite because gross additions = 0.

TABLE B.2

SASKATCHEWAN
SHORT-TERM REPLACEMENT COST ESTIMATES
1979-1988
(1988 constant dollars)

Year	Crude Oil Equivalent		Crude Oil		Marketable Natural Gas			
	Base Case ($/BOE)	Unadjusted Case ($/BOE)	Base Case ($/bbl)	Unadjusted Case ($/bbl)	Base Case ($/Mcf)	Unadjusted Case ($/Mcf)	Base Case ($/BOE)	Unadjusted Case ($/BOE)
1979		8.09		8.77		0.30		3.51
1980		7.77		8.42		0.20		2.40
1981		10.38		13.39		0.13		1.57
1982		7.54		9.75		0.06		0.74
1983		4.38		4.96		0.15		1.73
1984		4.99		5.88		0.18		2.16
1985	5.94	7.84	6.05	8.37	0.44	0.44	5.19	5.19
1986	7.14	6.59	7.64	6.89	0.46	0.46	5.44	5.44
1987	6.61	5.27	5.96	4.58	0.86	0.86	10.19	10.19
1988	4.70	3.44	4.42	2.98	0.47	0.47	5.59	5.59

SOURCE: Canadian Energy Research Institute.

APPENDIX C

LONG-TERM REPLACEMENT COST RESULTS

TABLE C.1

ALBERTA BASE CASE
CRUDE OIL EQUIVALENT
FINDING COSTS[a]
1970-1988
(1988 constant dollars per BOE)

Year	Yearly	3-Year Moving Average	5-Year Moving Average	7-Year Moving Average
1970				
1971				
1972	5.31			
1973	3.81			
1974	3.86	4.33		
1975	7.52	5.06		
1976	4.04	5.14	4.91	
1977	3.62	5.06	4.57	
1978	3.75	3.80	4.56	4.56
1979	7.82	5.06	5.35	4.92
1980	9.51	7.02	5.75	5.73
1981	15.58	10.97	8.05	7.40
1982	16.53	13.87	10.64	8.69
1983	11.57	14.56	12.20	9.77
1984	9.81	12.64	12.60	10.65
1985	7.93	9.77	12.28	11.25
1986	8.45	8.73	10.86	11.34
1987	7.07	7.82	8.97	10.99
1988	5.02	6.85	7.66	9.48

SOURCE: Canadian Energy Research Institute.

[a]Finding costs calculated as total exploration expenditures divided by fully appreciated hydrocarbon reserves dated back to the year of discovery. Crude oil equivalent based on an historical wellhead price equivalence of 11.8 thousand cubic feet of natural gas to one barrel of crude oil (see Table A.21). Base case refers to land expenditures and geological and geophysical expenditures lagged by two years and one year, respectively.

TABLE C.2

ALBERTA BASE CASE
CRUDE OIL EQUIVALENT
LONG-TERM REPLACEMENT COSTS[a]
1970-1988
(1988 constant dollars per BOE)

Year	Yearly	3-Year Moving Average	5-Year Moving Average	7-Year Moving Average
1970				
1971				
1972	9.87			
1973	7.39			
1974	8.60	8.62		
1975	18.35	11.45		
1976	9.73	12.23	10.79	
1977	7.90	11.99	10.39	
1978	7.50	8.37	10.42	9.90
1979	12.96	9.45	11.29	10.35
1980	14.99	11.82	10.62	11.43
1981	23.41	17.12	13.35	13.55
1982	26.63	21.68	17.10	14.73
1983	21.41	23.82	19.88	16.40
1984	19.48	22.51	21.19	18.06
1985	14.28	18.39	21.04	19.02
1986	15.08	16.28	19.38	19.33
1987	12.71	14.02	16.59	19.00
1988	10.27	12.69	14.36	17.12

SOURCE: Canadian Energy Research Institute.

[a]Long-term replacement costs calculated as total exploration and development expenditures divided by fully appreciated hydrocarbon reserves dated back to the year of discovery. Crude oil equivalent based on an historical wellhead price equivalence of 11.8 thousand cubic feet of natural gas to one barrel of crude oil (see Table A.21). Base case refers to land expenditures and geological and geophysical expenditures lagged by two years and one year, respectively; development expenditures are adjusted to reflect a five-year development profile.

TABLE C.3

ALBERTA BASE CASE
CRUDE OIL
FINDING COSTS[a]
1970-1988
(1988 constant dollars per barrel)

Year	Yearly	3-Year Moving Average	5-Year Moving Average	7-Year Moving Average
1970				
1971				
1972	12.03			
1973	1.99			
1974	4.86	6.29		
1975	8.79	5.21		
1976	5.46	6.37	6.63	
1977	1.70	5.32	4.56	
1978	1.21	2.79	4.40	5.15
1979	3.62	2.18	4.16	3.95
1980	8.11	4.31	4.02	4.82
1981	17.68	9.80	6.46	6.65
1982	11.80	12.53	8.48	7.08
1983	8.62	12.70	9.96	7.53
1984	9.92	10.11	11.22	8.71
1985	7.55	8.70	11.11	9.61
1986	10.56	9.34	9.69	10.61
1987	7.85	8.65	8.90	10.57
1988	6.09	8.17	8.39	8.91

SOURCE: Canadian Energy Research Institute.

[a]Finding costs calculated as crude oil exploration expenditures divided by fully appreciated crude oil reserves dated back to the year of discovery; crude oil exploration expenditures are calculated as total exploration expenditures multiplied by estimated crude oil exploratory intent. Base case refers to land expenditures and geological and geophysical expenditures lagged by two years and one year, respectively.

TABLE C.4

ALBERTA BASE CASE
CRUDE OIL
LONG-TERM REPLACEMENT COSTS[a]
1970-1988
(1988 constant dollars per barrel)

Year	Yearly	3-Year Moving Average	5-Year Moving Average	7-Year Moving Average
1970				
1971				
1972	28.05			
1973	4.51			
1974	15.19	15.92		
1975	32.36	17.35		
1976	24.15	23.90	20.85	
1977	7.41	21.31	16.72	
1978	4.79	12.12	16.78	16.64
1979	10.01	7.40	15.75	14.06
1980	20.51	11.77	13.38	16.35
1981	40.47	23.67	16.64	19.96
1982	28.52	29.84	20.86	19.41
1983	21.60	30.20	24.22	19.05
1984	23.64	24.59	26.95	21.36
1985	15.16	20.13	25.88	22.85
1986	20.98	19.93	21.98	24.41
1987	15.62	17.26	19.40	23.72
1988	15.22	17.28	18.13	20.11

SOURCE: Canadian Energy Research Institute.

[a]Long-term replacement costs calculated as crude oil exploration and development expenditures divided by fully appreciated crude oil reserves dated back to the year of discovery; crude oil exploration and development expenditures are calculated as total exploration expenditures multiplied by estimated crude oil exploratory intent plus total development expenditures multiplied by estimated crude oil development intent. Base case refers to land expenditures and geological and geophysical expenditures lagged by two years and one year, respectively; development expenditures are adjusted to reflect a five-year development profile.

TABLE C.5

ALBERTA BASE CASE MARKETABLE NATURAL GAS FINDING COSTS[a] 1970-1988 (1988 constant dollars per Mcf)

Year	Yearly	3-Year Moving Average	5-Year Moving Average	7-Year Moving Average
1970				
1971				
1972	0.37			
1973	0.51			
1974	0.31	0.40		
1975	0.62	0.48		
1976	0.33	0.42	0.43	
1977	0.39	0.44	0.43	
1978	0.57	0.43	0.44	0.44
1979	0.96	0.64	0.57	0.53
1980	0.85	0.79	0.62	0.58
1981	1.26	1.03	0.81	0.71
1982	1.74	1.29	1.08	0.87
1983	1.33	1.44	1.23	1.02
1984	0.82	1.30	1.20	1.08
1985	0.73	0.96	1.18	1.10
1986	0.55	0.70	1.03	1.04
1987	0.52	0.60	0.79	0.99
1988	0.35	0.47	0.59	0.86

SOURCE: Canadian Energy Research Institute.

[a]Finding costs calculated as marketable natural gas exploration expenditures divided by fully appreciated marketable natural gas reserves dated back to the year of discovery; marketable natural gas exploration expenditures are calculated as total exploration expenditures multiplied by estimated natural gas exploratory intent. Base case refers to land expenditures and geological and geophysical expenditures lagged by two years and one year, respectively.

TABLE C.6

ALBERTA BASE CASE
MARKETABLE NATURAL GAS
LONG-TERM REPLACEMENT COSTS[a]
1970-1988
(1988 constant dollars per Mcf)

Year	Yearly	3-Year Moving Average	5-Year Moving Average	7-Year Moving Average
1970				
1971				
1972	0.62			
1973	0.92			
1974	0.62	0.72		
1975	1.31	0.95		
1976	0.65	0.86	0.82	
1977	0.69	0.89	0.84	
1978	0.91	0.75	0.84	0.82
1979	1.31	0.97	0.97	0.91
1980	1.09	1.10	0.93	0.94
1981	1.52	1.31	1.10	1.07
1982	2.12	1.58	1.39	1.18
1983	1.79	1.81	1.57	1.35
1984	1.24	1.72	1.55	1.42
1985	1.08	1.37	1.55	1.45
1986	0.80	1.04	1.40	1.38
1987	0.76	0.88	1.13	1.33
1988	0.53	0.70	0.88	1.19

SOURCE: Canadian Energy Research Institute.

[a]Long-term replacement costs calculated as marketable natural gas exploration and development expenditures divided by fully appreciated marketable natural gas reserves dated back to the year of discovery; marketable natural gas exploration and development expenditures are calculated as total exploration expenditures multiplied by estimated natural gas exploratory intent plus total development expenditures multiplied by estimated natural gas development intent. Base case refers to land expenditures and geological and geophysical expenditures lagged by two years and one year, respectively; development expenditures are adjusted to reflect a five-year development profile.

TABLE C.7

ALBERTA BASE CASE
MARKETABLE NATURAL GAS
FINDING COSTS[a]
1970-1988
(1988 constant dollars per BOE)

Year	Yearly	3-Year Moving Average	5-Year Moving Average	7-Year Moving Average
1970				
1971				
1972	4.38			
1973	5.99			
1974	3.66	4.68		
1975	7.26	5.64		
1976	3.84	4.92	5.03	
1977	4.62	5.24	5.07	
1978	6.72	5.06	5.22	5.21
1979	11.35	7.56	6.76	6.21
1980	10.05	9.37	7.32	6.79
1981	14.90	12.10	9.53	8.39
1982	20.57	15.17	12.72	10.29
1983	15.65	17.04	14.50	11.98
1984	9.68	15.30	14.17	12.70
1985	8.62	11.32	13.88	12.97
1986	6.43	8.24	12.19	12.27
1987	6.08	7.04	9.29	11.70
1988	4.15	5.55	6.99	10.17

SOURCE: Canadian Energy Research Institute.

[a]Finding costs calculated as marketable natural gas exploration expenditures divided by fully appreciated marketable natural gas reserves dated back to the year of discovery; marketable natural gas exploration expenditures are calculated as total exploration expenditures multiplied by estimated natural gas exploratory intent. Base case refers to land expenditures and geological and geophysical expenditures lagged by two years and one year, respectively.

TABLE C.8

ALBERTA BASE CASE
MARKETABLE NATURAL GAS
LONG-TERM REPLACEMENT COSTS[a]
1970-1988
(1988 constant dollars per BOE)

Year	Yearly	3-Year Moving Average	5-Year Moving Average	7-Year Moving Average
1970				
1971				
1972	7.36			
1973	10.82			
1974	7.28	8.49		
1975	15.50	11.20		
1976	7.69	10.15	9.73	
1977	8.15	10.44	9.89	
1978	10.68	8.84	9.86	9.64
1979	15.44	11.42	11.49	10.79
1980	12.86	12.99	10.96	11.08
1981	17.93	15.41	13.01	12.61
1982	25.02	18.61	16.39	13.97
1983	21.14	21.36	18.48	15.89
1984	14.58	20.25	18.31	16.81
1985	12.69	16.14	18.27	17.09
1986	9.42	12.23	16.57	16.23
1987	9.02	10.37	13.37	15.69
1988	6.29	8.24	10.40	14.02

SOURCE: Canadian Energy Research Institute.

[a]Long-term replacement costs calculated as marketable natural gas exploration and development expenditures divided by fully appreciated marketable natural gas reserves dated back to the year of discovery; marketable natural gas exploration and development expenditures are calculated as total exploration expenditures multiplied by estimated natural gas exploratory intent plus total development expenditures multiplied by estimated natural gas development intent. Base case refers to land expenditures and geological and geophysical expenditures lagged by two years and one year, respectively; development expenditures are adjusted to reflect a five-year development profile.

TABLE C.9

ALBERTA UNADJUSTED CASE
CRUDE OIL EQUIVALENT
FINDING COSTS[a]
1970-1988
(1988 constant dollars per BOE)

Year	Yearly	3-Year Moving Average	5-Year Moving Average	7-Year Moving Average
1970	10.09			
1971	7.13			
1972	5.05	7.42		
1973	3.72	5.30		
1974	4.32	4.36	6.06	
1975	7.83	5.29	5.61	
1976	4.75	5.63	5.13	6.13
1977	5.83	6.14	5.29	5.52
1978	5.41	5.33	5.63	5.27
1979	8.86	6.70	6.54	5.82
1980	10.63	8.30	7.10	6.80
1981	11.75	10.41	8.50	7.87
1982	10.33	10.91	9.40	8.22
1983	9.58	10.56	10.23	8.91
1984	10.79	10.24	10.62	9.62
1985	8.64	9.67	10.22	10.08
1986	6.29	8.57	9.13	9.72
1987	5.78	6.90	8.22	9.02
1988	5.47	5.84	7.39	8.13

SOURCE: Canadian Energy Research Institute.

[a]Finding costs calculated as total exploration expenditures divided by fully appreciated hydrocarbon reserves dated back to the year of discovery. Crude oil equivalent based on an historical wellhead price equivalence of 11.8 thousand cubic feet of natural gas to one barrel of crude oil (see Table A.21). Unadjusted case refers to using unadjusted expenditure data.

TABLE C.10

ALBERTA UNADJUSTED CASE
CRUDE OIL EQUIVALENT
LONG-TERM REPLACEMENT COSTS[a]
1970-1988
(1988 constant dollars per BOE)

Year	Yearly	3-Year Moving Average	5-Year Moving Average	7-Year Moving Average
1970	16.69			
1971	13.00			
1972	9.61	13.10		
1973	7.29	9.97		
1974	9.06	8.66	11.13	
1975	18.67	11.67	11.53	
1976	10.44	12.72	11.02	12.11
1977	10.10	13.07	11.11	11.17
1978	9.17	9.90	11.49	10.62
1979	14.00	11.09	12.48	11.25
1980	16.12	13.10	11.97	12.51
1981	19.59	16.57	13.80	14.01
1982	20.44	18.72	15.86	14.27
1983	19.43	19.82	17.92	15.55
1984	20.47	20.12	19.21	17.03
1985	14.99	18.30	18.99	17.87
1986	12.92	16.13	17.65	17.71
1987	11.42	13.11	15.85	17.04
1988	10.73	11.69	14.11	15.77

SOURCE: Canadian Energy Research Institute.

[a]Long-term replacement costs calculated as total exploration and development expenditures divided by fully appreciated hydrocarbon reserves dated back to the year of discovery. Crude oil equivalent based on an historical wellhead price equivalence of 11.8 thousand cubic feet of natural gas to one barrel of crude oil (see Table A.21). Unadjusted case refers to using unadjusted expenditure data except for adjusting development expenditures to reflect a five-year development profile.

TABLE C.11

ALBERTA UNADJUSTED CASE CRUDE OIL FINDING COSTS[a] 1970-1988 (1988 constant dollars per barrel)

Year	Yearly	3-Year Moving Average	5-Year Moving Average	7-Year Moving Average
1970	13.63			
1971	6.99			
1972	9.21	9.95		
1973	1.46	5.89		
1974	5.11	5.26	7.28	
1975	8.29	4.95	6.21	
1976	5.40	6.27	5.90	7.16
1977	2.63	5.44	4.58	5.59
1978	1.98	3.34	4.68	4.87
1979	5.08	3.23	4.67	4.28
1980	9.67	5.58	4.95	5.45
1981	14.36	9.70	6.74	6.77
1982	10.04	11.36	8.22	7.02
1983	9.20	11.20	9.67	7.57
1984	11.92	10.39	11.04	8.89
1985	8.72	9.95	10.85	9.86
1986	7.77	9.47	9.53	10.24
1987	6.09	7.53	8.74	9.73
1988	6.00	6.62	8.10	8.54

SOURCE: Canadian Energy Research Institute.

[a]Finding costs calculated as crude oil exploration expenditures divided by fully appreciated crude oil reserves dated back to the year of discovery; crude oil exploration expenditures are calculated as total exploration expenditures multiplied by estimated crude oil exploratory intent. Unadjusted case refers to using unadjusted expenditure data.

TABLE C.12

ALBERTA UNADJUSTED CASE
CRUDE OIL
LONG-TERM REPLACEMENT COSTS[a]
1970-1988
(1988 constant dollars per barrel)

Year	Yearly	3-Year Moving Average	5-Year Moving Average	7-Year Moving Average
1970	30.61			
1971	14.53			
1972	25.26	23.47		
1973	3.98	14.59		
1974	15.46	14.90	17.97	
1975	31.90	17.11	18.22	
1976	24.12	23.83	20.14	20.84
1977	8.35	21.46	16.76	17.66
1978	5.56	12.68	17.08	16.37
1979	11.48	8.46	16.28	14.41
1980	22.10	13.04	14.32	16.99
1981	37.18	23.59	16.93	20.10
1982	26.78	28.68	20.62	19.37
1983	22.19	28.72	23.95	19.09
1984	25.66	24.88	26.78	21.56
1985	16.34	21.40	25.63	23.10
1986	18.20	20.07	21.84	24.06
1987	13.87	16.14	19.25	22.89
1988	15.14	15.74	17.84	19.74

SOURCE: Canadian Energy Research Institute.

[a]Long-term replacement costs calculated as crude oil exploration and development expenditures divided by fully appreciated crude oil reserves dated back to the year of discovery; crude oil exploration and development expenditures are calculated as total exploration expenditures multiplied by estimated crude oil exploratory intent plus total development expenditures multiplied by estimated crude oil development intent. Unadjusted case refers to using unadjusted expenditure data except for adjusting development expenditures to reflect a five-year development profile.

TABLE C.13

ALBERTA UNADJUSTED CASE MARKETABLE NATURAL GAS FINDING COSTS[a] 1970-1988 (1988 constant dollars per Mcf)

Year	Yearly	3-Year Moving Average	5-Year Moving Average	7-Year Moving Average
1970	0.78			
1971	0.61			
1972	0.38	0.59		
1973	0.54	0.51		
1974	0.35	0.43	0.53	
1975	0.66	0.52	0.51	
1976	0.39	0.47	0.47	0.53
1977	0.63	0.56	0.52	0.51
1978	0.80	0.61	0.57	0.54
1979	1.02	0.82	0.70	0.63
1980	0.93	0.92	0.76	0.68
1981	0.92	0.96	0.86	0.77
1982	0.90	0.92	0.91	0.80
1983	0.86	0.89	0.93	0.87
1984	0.80	0.85	0.88	0.89
1985	0.72	0.79	0.84	0.88
1986	0.41	0.64	0.74	0.79
1987	0.46	0.53	0.65	0.72
1988	0.43	0.43	0.56	0.65

SOURCE: Canadian Energy Research Institute.

[a]Finding costs calculated as marketable natural gas exploration expenditures divided by fully appreciated marketable natural gas reserves dated back to the year of discovery; marketable natural gas exploration expenditures are calculated as total exploration expenditures multiplied by estimated natural gas exploratory intent. Unadjusted case refers to using unadjusted expenditure data.

TABLE C.14

ALBERTA UNADJUSTED CASE
MARKETABLE NATURAL GAS
LONG-TERM REPLACEMENT COSTS[a]
1970-1988
(1988 constant dollars per Mcf)

Year	Yearly	3-Year Moving Average	5-Year Moving Average	7-Year Moving Average
1970	1.11			
1971	1.02			
1972	0.63	0.92		
1973	0.95	0.87		
1974	0.66	0.75	0.88	
1975	1.35	0.99	0.92	
1976	0.72	0.91	0.86	0.92
1977	0.93	1.00	0.92	0.90
1978	1.14	0.93	0.96	0.91
1979	1.37	1.14	1.10	1.02
1980	1.17	1.22	1.07	1.05
1981	1.18	1.24	1.16	1.12
1982	1.27	1.21	1.23	1.11
1983	1.32	1.26	1.26	1.20
1984	1.22	1.27	1.23	1.24
1985	1.06	1.20	1.21	1.23
1986	0.67	0.98	1.11	1.13
1987	0.70	0.81	0.99	1.06
1988	0.61	0.66	0.85	0.98

SOURCE: Canadian Energy Research Institute.

[a]Long-term replacement costs calculated as marketable natural gas exploration and development expenditures divided by fully appreciated marketable natural gas reserves dated back to the year of discovery; marketable natural gas exploration and development expenditures are calculated as total exploration expenditures multiplied by estimated natural gas exploratory intent plus total development expenditures multiplied by estimated natural gas development intent. Unadjusted case refers to using unadjusted expenditure data except for adjusting development expenditures to reflect a five-year development profile.

TABLE C.15

ALBERTA UNADJUSTED CASE
MARKETABLE NATURAL GAS
FINDING COSTS[a]
1970-1988
(1988 constant dollars per BOE)

Year	Yearly	3-Year Moving Average	5-Year Moving Average	7-Year Moving Average
1970	9.18			
1971	7.22			
1972	4.48	6.96		
1973	6.41	6.03		
1974	4.16	5.02	6.29	
1975	7.74	6.10	6.00	
1976	4.66	5.52	5.49	6.26
1977	7.48	6.63	6.09	6.02
1978	9.44	7.19	6.70	6.34
1979	12.03	9.65	8.27	7.42
1980	11.00	10.83	8.92	8.07
1981	10.91	11.32	10.18	9.04
1982	10.58	10.83	10.80	9.44
1983	10.11	10.54	10.93	10.22
1984	9.47	10.05	10.42	10.51
1985	8.47	9.35	9.91	10.37
1986	4.88	7.61	8.70	9.35
1987	5.37	6.24	7.66	8.54
1988	5.04	5.10	6.65	7.70

SOURCE: Canadian Energy Research Institute.

[a]Finding costs calculated as marketable natural gas exploration expenditures divided by fully appreciated marketable natural gas reserves dated back to the year of discovery; marketable natural gas exploration expenditures are calculated as total exploration expenditures multiplied by estimated natural gas exploratory intent. Unadjusted case refers to using unadjusted expenditure data.

TABLE C.16

ALBERTA UNADJUSTED CASE
MARKETABLE NATURAL GAS
LONG-TERM REPLACEMENT COSTS[a]
1970-1988
(1988 constant dollars per BOE)

Year	Yearly	3-Year Moving Average	5-Year Moving Average	7-Year Moving Average
1970	13.13			
1971	12.06			
1972	7.46	10.88		
1973	11.25	10.26		
1974	7.78	8.83	10.34	
1975	15.98	11.67	10.90	
1976	8.51	10.75	10.19	10.88
1977	11.01	11.83	10.90	10.58
1978	13.40	10.97	11.33	10.77
1979	16.11	13.51	13.00	12.00
1980	13.82	14.45	12.57	12.37
1981	13.95	14.63	13.66	13.25
1982	15.04	14.27	14.46	13.12
1983	15.60	14.86	14.90	14.13
1984	14.37	15.00	14.56	14.61
1985	12.54	14.17	14.30	14.49
1986	7.86	11.59	13.08	13.31
1987	8.31	9.57	11.74	12.52
1988	7.17	7.78	10.05	11.56

SOURCE: Canadian Energy Research Institute.

[a]Long-term replacement costs calculated as marketable natural gas exploration and development expenditures divided by fully appreciated marketable natural gas reserves dated back to the year of discovery; marketable natural gas exploration and development expenditures are calculated as total exploration expenditures multiplied by estimated natural gas exploratory intent plus total development expenditures multiplied by estimated natural gas development intent. Unadjusted case refers to using unadjusted expenditure data except for adjusting development expenditures to reflect a five-year development profile.

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